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BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
CHAIRMAN
WILLIAM A. MUNDELL
COMMISSIONER
MARC SPITZER
COMMISSIONER
MIKE GLEASON
COMMISSIONER
KRISTIN K. MAYES
COMMISSIONER

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AZ CORP COMMISSION
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IN THE MATTER OF THE APPLICATION OF BLACK MOUNTAIN SEWER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	Docket No. SW-02361A-05-0657

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Marylee Diaz Cortez, CPA, and William A. Rigsby in the above-referenced matter.

RESPECTFULLY SUBMITTED this 9th day of March, 2006.

Scott Wakefield for
Daniel W. Pozefsky
Attorney

AN ORIGINAL AND THIRTEEN COPIES of the foregoing filed this 9th day of March, 2006 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/ mailed this 9th day of March, 2006 to:

Teena Wolfe
Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Christopher Kempley, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Ernest Johnson, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Jay L. Shapiro
Patrick J. Black
Fennemore Craig, P.C.
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012

Robert E. Williams, Vice Chair
The Boulders Homeowners Association
P. O. Box 2037
Carefree, AZ 85377

M. M. Shirtzinger
34773 N. Indian Camp Trail
Scottsdale, AZ 85262

Thomas K. Chenal
Mohr, Hackett, Pederson, Blakley & Randolph, P.C.
7047 East Greenway Parkway
Suite 155
Scottsdale, AZ 85254

By Ernestine Gamble
Ernestine Gamble

BLACK MOUNTAIN SEWER CORPORATION

DOCKET NO. SW-02361A-05-0657

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

March 9, 2006

INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present recommendations resulting from my review and analysis of Black Mountain Sewer Company's ("Black Mountain" or "Company") request for an increase in rates.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data, and performed analytical procedures necessary to understand the Company's application. My recommendations are based on these analyses. Procedures performed included the formulation and analysis of several sets of data requests, the review and analysis of Staff requested data, as well as a review of annual reports and prior Commission decisions.

Q. What areas will you address in your testimony?

A. I will address rate base. RUCO witness William Rigsby will address the remaining issues of operating income, cost of capital, rate design, as well as sponsor RUCO's recommended revenue requirement.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-6.

SUMMARY

Q. Please summarize the recommendations and adjustments you address in your testimony.

A. I address the following issues in my testimony:

<u>Scottsdale Wastewater Treatment Capacity</u> - This adjustment corrects the fallacy that this intangible asset is an "operating lease" and properly reflects the Scottsdale Capacity as a depreciable rate base asset.

<u>Post-test-Year Plant</u> - This adjustment removes post-test-year line extensions from rate base and includes the post-test-year cost of replacing a sewer chlorination system.

Accumulated Deferred Income Taxes - The adjustment decreases rate base by $161,250 to include Black Mountain's allocated portion of Accumulated Deferred Income Taxes.

Working Capital - This adjustment decreases the Company's requested level of working capital to reflect the fact that customers are required to prepay their sewer bill.

RATE BASE

Rate Base Adjustment #1 - Scottsdale Wastewater Treatment Capacity

Q. Please discuss the Company's proposed ratemaking treatment of the Scottsdale Wastewater Treatment Capacity (Scottsdale Capacity).

A. The Company proposes to pretend that the capacity rights that it owns in Scottsdale's Wastewater Treatment Plant were, in fact, an operating lease. As a result, the Company has made a pro forma calculation that imputes a hypothetical operating lease expense of $189,622, and seeks recovery of this "expense" from ratepayers.

Q. Why has Black Mountain proposed this hypothetical accounting for the capacity rights it owns in the Scottsdale Wastewater Treatment Plant?

A. The Company's testimony offers no explanation for its proposed operating lease treatment of the capacity rights. However, it appears that the Company's proposal may be based on a 1996 Boulders Carefree Sewer Corporation decision where the Commission authorized an "income statement methodology"[1] for the ratemaking treatment of the capacity rights.

Q. Did Boulders Carefree Sewer Corporation actually have an operating lease with Scottsdale in 1996?

A. No. Boulders Carefree Sewer Corporation purchased the Scottsdale Treatment Capacity from the City of Scottsdale with the proceeds of a loan from its parent company--Boulders Joint Venture. Thus, the "operating lease" treatment was a fallacy even at that time.

Q. Is the "operating lease" treatment an even greater fallacy today?

A. Yes. Boulders Carefree Sewer Corporation no longer exists, nor does the loan that Boulders Joint Venture made to Boulders Carefree Sewer Corporation to purchase the capacity. Thus, any nexus that might have led to the "operating lease" treatment authorized in Decision No. 59944 no longer exists. Algonquin Water Resources of America, Inc. ("Algonquin") purchased the stock of Boulders Carefree Sewer Corporation in March 2001[2]. The purchase was financed with equity from Algonquin, and debt in the form of promissory notes from Black Mountain to Algonquin. Together, the debt and equity are the capitalization that supports the assets of what is now Black Mountain Sewer Company. Black Mountain has no "lease" with Scottsdale, but rather has an asset on its balance

[1] Decision No. 59944 at page 6.
[2] See the testimony of William A. Rigsby for more background on Algonquin.

sheet for the Scottsdale Capacity, and a combination of debt and equity that support it.

Q. How are assets and debt/equity appropriately treated under rate of return regulation?

A. Assets, if used and useful and prudent, are included in rate base. Debt and equity are included in the capital structure upon which a fair rate of return is calculated. Depreciation on the assets is included in utility operating expenses. Tax deductions for the interest expense on the debt are included in the income tax expense calculation, and taxes on the utility's earnings on its assets are included in the Gross Revenue Conversion Factor. The rate of return regulatory model is designed to provide full recovery of, and return on all of a company's assets.

Q. Have you made an adjustment to the Company's proposed "operating lease" accounting?

A. Yes. As just discussed, this "operating lease" accounting was a fallacy when authorized in 1996 for Boulder Carefree Sewer, and is an even greater fallacy today for Black Mountain. Accordingly, Mr. Rigsby in his Operating Income Adjustment #1 removes this $189,622 fictitious "lease expense" shown on Back Mountain's income statement. My Rate Base Adjustment #1 makes the appropriate adjustments to the rate base to provide rate recognition of these assets.

Q. Specifically describe the rate base adjustments necessary to afford this asset the appropriate rate recognition.

A. As shown on Schedule MDC-3, four rate base adjustments are necessary to afford the appropriate rate treatment of the Scottsdale Capacity. The first adjustment is to increase Gross Plant in Service by $1,913,706 to recognize the original cost of the Scottsdale Capacity purchased in 1996 and the original cost of the additional capacity purchased in 1997.

The second adjustment increases accumulated depreciation by $778,111 to reflect the cumulative effect of the Company's 5% depreciation rate over the ensuing years since the capacity purchases.

The third adjustment increases the Contribution in Aid of Construction (CIAC) balance by $453,706 to include CIACs that were specifically utilized to fund the capacity purchases. This portion of the adjustment is necessary because the Company had made a pro forma adjustment to remove these CIAC balances as part of their "operating lease" ratemaking treatment. Since I have appropriately afforded rate base treatment for the Scottsdale Capacity, likewise it is appropriate to include the CIAC balances that support that capacity in rate base.

The fourth adjustment increases Accumulated Amortization of CIAC by $184,528 to reflect the cumulative effect of a 5% amortization rate over the ensuing years since the capacity purchases.

Q. How does using the correct rate of return methodology vs. the Company's "operating lease" methodology affect the revenue requirement?

A. Use of the correct rate of return ratemaking methodology has the affect of decreasing revenue requirements when compared with the Company's "operating lease" methodology.

Q. Why is this so?

A. Aside from the fact that the "operating lease" methodology was a complete fallacy, its greatest shortcoming is that it doesn't give ratepayers credit for the portion of the Scottsdale Capacity that they have paid over the years. While ratepayers are paying for 5% of this plant capacity each year through "operating lease" expense, the "operating lease" methodology never provides credit for the portion of the capacity that ratepayers have already paid for. When the correct ratemaking methodology is used to account for this capacity, that credit is reflected in the Accumulated Depreciation balance that serves to decrease rate base and, in turn, decrease rates. The "operating lease" methodology robs ratepayers of this credit.

Q. Are there any other adjustments that are necessary to reflect rate of return ratemaking for the Scottsdale Capacity?

A. Yes. RUCO has increased depreciation expense to include depreciation of the Scottsdale Capacity, and computed the appropriate income tax effects. These adjustments are discussed in RUCO witness William A. Rigsby's testimony.

Rate Base Adjustment #2 - Post-Test-Year Plant in Service

Q. Is the Company requesting any post-test-year plant in service?

A. Yes. The Company is requesting $94,297 in post-test-year plant additions, of which $24,706 is related to line extensions and $69,590 is for the replacement of defective chlorination equipment.

Q. Do you agree with these pro forma adjustments?

A. No. As a general policy, RUCO does not agree with the rate base recognition of post-test-year plant because of matching problems. In the instant case, that problem is further aggravated by the fact that some of the post-test-year plant is line extensions, which will create additional revenue, causing further matching problems.

Q. Even in those cases where the Commission has allowed rate base treatment of post-test-year plant, has it done so for revenue producing plant?

A. No. The Commission has consistently limited post-test year plant to *non*-revenue producing plant, specifically because of the inherent matching problem with revenue producing plant.

Q. Please discuss the other post-test-year project the Company is seeking recovery of.

A. In December 2003, the Company made a determination that its existing chlorine gas system was malfunctioning, had become dangerous, and needed to be replaced. During the test year the Company took bids on the replacement, and the work was subsequently completed after the end of the test year. In its application, the Company estimated the completion cost at $69,590. The actual completed cost was $85,699.

Q. What are you recommending regarding the pro forma post-test-year plant?

A. I recommend that the post-test-year line extensions be excluded from rate base. These plant items are revenue producing and will result in ratemaking mismatches. I recommend the rate base inclusion of the post-test-year chlorination system. While RUCO does not generally support post-test year plant, in this case there are safety issues involved, which warrant an exception to RUCO's policy.

Q. What adjustment have you made?

A. As shown on Schedule MDC-4, the net effect of disallowing the line extensions and increasing the cost of the chlorination system to actual cost is a $8,597 decrease in rate base.

Rate Base Adjustment #3 - Accumulated Deferred Income Taxes

Q. What amount of Accumulated Deferred Income Taxes (ADIT) has Black Mountain included in rate base?

A. Black Mountain's requested rate base reflects a zero balance for ADIT.

Q. Why are there no ADIT balances; doesn't Black Mountain take advantage of accelerated tax depreciation?

A. I asked the Company this question in RUCO data request 2.7. The Company responded that it files a consolidated tax return with its parent company, and that consolidated ADIT balances do reside on the parent company's books. However, ADIT is not recorded on Black Mountain's books.

Q. Is Black Mountain the only Arizona utility that files a consolidated tax return?

A. No. Most of Arizona's large utilities, as well as many smaller utilities, have parent company structures and file consolidated tax returns. These include Arizona-American Water Company, Arizona Water Company, Arizona Public Service Company, Tucson Electric Power Company, and Qwest Corporation.

Q. Do these other utilities that file consolidated tax returns also omit their ADIT balances from their regulated rate bases?

A. No. All of these utilities' rate bases include an allocated portion of the consolidated ADIT balance in their rate bases. The fact that Black Mountain files a consolidated tax return with its parent is not justification for failing to recognize Black Mountain's portion of the ADIT balances in rate base. If the filing of a consolidated tax return were justification for omitting ADIT from Black Mountain's rate base, it logically would follow that Income Tax Expense should be omitted from the Company's test year operating expenses. However, in the instant case the Company has included Black Mountain's allocated share of the consolidated income tax expense in its revenue requirement. All I am recommending is that the Company reflect the same type of allocation for its ADIT balances.

Q. What adjustment have you made?

A. As shown on Schedule MDC-5, I have identified the consolidated ADIT balance for Algonquin as a whole, and then allocated a portion to Black Mountain based on the ratio of the purchase price of Black Mountain to Algonquin's total assets. These amounts were all obtained from Algonquin's 2004 Annual Report. The amounts shown in the Annual

Report are in Canadian dollars; therefore, as shown on line 6 of Schedule MDC-5, I have converted these amounts to American dollars. This results in a $161,250 decrease in Black Mountain's rate base for its allocated portion of ADIT.

Rate Base Adjustment #4 - Cash Working Capital

Q. Please discuss the Company's cash working capital request.

A. The Company has computed a cash working capital requirement of $130,508. Black Mountain calculates this amount based on the formula method of determining cash working capital. The formula method assumes that there is an average lag of 45 days for operating maintenance and expenses, and an average lag of 15 days for purchased power expense.

Q. Do you agree with this methodology?

A. In general, it is appropriate to use the formula method only for small utility companies. The formula method's major flaw is that it always generates a positive level of working capital, when in fact a full lead/lag study may reveal that a given utility's cash working capital is, in fact, negative.

Q. What set of circumstances will result in negative working capital?

A. Negative working capital will result when revenues are received prior to expenses having to be paid (i.e. when a utility has a revenue lead or a utility's expense lag exceeds its revenue lag).

Q. Does Black Mountain satisfy either of these criteria?

A. Yes. Black Mountain's expense lag exceeds its revenue lag and, as a result, has a negative cash working capital requirement.

Q. Please explain.

A. Black Mountain, unlike many utilities, bills for service prior to fully rendering the service. As shown on Schedule MDC-6, customers are required to pay for their service in a given month prior to receiving an entire month of service (bill due dates are on or around the 22nd of the month). The due date, when compared to the mid-point of the service period of the 15th, yields a revenue lag of approximately 7 or 8 days. The Company requests a 45-day lag period for its O&M expenses and a 15-day lag period for its purchased power. As shown on Schedule MDC-6, page 2, this amounts to an average expense lag of approximately 43 days. Thus, in this case the Company's expense lag of 43 days exceeds its revenue lag of 8 days. Because ratepayers provide payment for their sewer service prior to when the utility must pay its bills, ratepayers have already provided the Company with cash working capital in the form of prepayments.

Q. What amount of cash working capital are you recommending?

A. As shown on Schedule MDC-6, page 1, I am recommending negative working capital of $87,253, which requires a $217,761 decrease to the level requested by the Company. While this adjustment is primarily attributable to the Company's failure to consider its prepayment policy in its cash working capital request, some of the adjustment is attributable to the difference in the Company's recommended expense levels vs. RUCO's.

Rate Base Adjustment #5 - Capitalized Expenses

Q. Please discuss rate base adjustment #5.

A. This adjustment increases rate base by $6,693 to include two plant items that the Company expensed during the test year that should more appropriately be capitalized. This adjustment is more fully discussed in the testimony of William A. Rigsby.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION:	University of Michigan, Dearborn B.S.A., Accounting 1989
CERTIFICATION:	Certified Public Accountant - Michigan Certified Public Accountant - Arizona
EXPERIENCE:	Audit Manager Residential Utility Consumer Office Phoenix, Arizona 85007 July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office

Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office

Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office

Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Corporation	T-01051B-03-0454 & T-00000D-00-0672	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-04-0408	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0280	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-04-0876	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0405	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0718	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-06-0009	Residential Utility Consumer Office

BLACK MOUNTAIN SEWER CORPORATION
DOCKET NO. SW-02361A-05-0657
TABLE OF CONTENTS TO SCHEDULES MDC

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
RATE BASE - ORIGINAL COST

DOCKET NO. SW-02361A-05-0657
SCHEDULE MDC-1

LINE NO.	DESCRIPTION	(A) COMPANY TEST YEAR AS FILED	(B) RUCO TEST YEAR ADJUSTMENTS	(C) RUCO TEST YEAR AS ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$ 8,464,745	$ 1,911,802	$ 10,376,547
2	ACCUMULATED DEPRECIATION	(4,366,379)	(778,227)	(5,144,606)
3	NET UTILITY PLANT IN SERVICE	$ 4,098,366	$ 1,133,575	$ 5,231,941
4	ADVANCES IN AID OF CONSTRUCTION (AIAC)	(1,315,900)	-	(1,315,900)
5	CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)	(5,346,615)	(453,706)	(5,800,321)
6	ACCUMULATED AMORTIZATION OF CIAC	3,308,578	184,528	3,493,106
7	CUSTOMER METER DEPOSITS	3,000	-	3,000
8	DEFERRED INCOME TAXES AND CREDITS	-	(161,250)	(161,250)
9	PREPAIDS	9,512	-	9,512
10	ALLOWANCE FOR WORKING CAPITAL	130,508	(217,761)	(87,253)
11	TOTAL RATE BASE	$ 887,449	$ 485,385	$ 1,372,834

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1
COLUMN (B): SCHEDULE MDC-2
COLUMN (C): COLUMN (A) + COLUMN (B)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
SUMMARY OF RATE BASE ADJUSTMENTS

DOCKET NO. SW-02361A-05-0657
SCHEDULE MDC-2

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
LINE NO.	DESCRIPTION	COMPANY PROPOSED	ADJ. #1	ADJ. #2	ADJ. #3	ADJ. #4	ADJ. #5	RUCO ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$ 8,464,745	$ 1,913,706	$ (8,597)		$ -	$ 6,693	$ 10,376,547
2	ACCUMULATED DEPRECIATION	(4,366,379)	$ (778,111)				(116)	(5,144,606)
3	NET UTILITY PLANT IN SERVICE	$ 4,098,366	$ 1,135,595	$ (8,597)	$ -	$ -	$ 6,577	$ 5,231,941
4	ADVANCES IN AID OF CONSTRUCTION (AIAC)	(1,315,900)						(1,315,900)
5	CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)	(5,346,615)	(453,706)					(5,800,321)
6	ACCUMULATED AMORTIZATION OF CIAC	3,308,578	184,528					3,493,106
7	CUSTOMER METER DEPOSITS	3,000						3,000
8	DEFERRED INCOME TAXES AND CREDITS	-			(161,250)			(161,250)
9	PREPAIDS	9,512						9,512
10	ALLOWANCE FOR WORKING CAPITAL	130,508				(217,761)		(87,253)
11	TOTAL RATE BASE	$ 887,449	$ 866,417	$ (8,597)	$ (161,250)	$ (217,761)	$ 6,577	$ 1,372,834

ADJUSTMENT #:	REFERENCE:
1 SCOTTSDALE WASTEWATER TREATMENT CAPACITY	SCH. MDC-3
2 POST-TEST YEAR PLANT	SCH. MDC-4
3 ACCUMULATED DEFERRED INCOME TAXES	SCH. MDC-5
4 WORKING CAPITAL	SCH. MDC-6
5 CAPITALIZED EXPENSES	DIRECT TESTIMONY MDC

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
RATE BASE ADJ. #1 - SCOTTSDALE CAPACITY

DOCKET NO. SW-02361A-05-0657
SCHEDULE MDC-3

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	SCOTTSDALE CAPACITY - AUG. 1996	$ 1,260,000	DECISION NO. 59944
2	SCOTTSDALE CAPACITY - JUNE 1997	653,706	DECISION NO. 60240
3	GROSS PLANT	$ 1,913,706	LINE 1 + LINE 2
4	ACCUM. DEPREC. - 1996 CAPACITY	530,250	NOTE (A)
5	ACCUM. DEPREC. - 1997 CAPACITY	247,861	NOTE (B)
6	TOTAL ACCUM. DEPREC.	$ 778,111	LINE 4 + LINE 5
7			
8	CIAC - AUG. 1996 CAPACITY	300,000	DECISION NO. 59944
9	CIAC - JUNE 1997 CAPACITY	153,706	DECISION NO. 60240
10	TOTAL CIAC	$ 453,706	LINE 7 + LINE 8
11	ACCUM. AMORT. CIAC - 1996 CAPACITY	126,250	NOTE (C)
12	ACCUM. AMORT. CIAC - 1997 CAPACITY	58,278	NOTE (D)
13	TOTAL ACCUM. AMORT. CIAC	$ 184,528	LINE 10 + LINE 11

NOTES
(A) $1,260,000/20 YEARS x 8.4167 YEARS
(B) $653,706/20 YEARS x 7.5834 YEARS
(C) $300,000/20 YEARS x 8.4167 YEARS
(D) $153,706/20 YEARS x 7.5834 YEARS

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
RATE BASE ADJ #2 - POST-TEST YEAR PLANT

DOCKET NO. SW-02361A-05-0657
SCHEDULE MDC-4

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	REMOVE POST T/Y LINE EXTENSIONS	$ (24,706)	COMPANY SCH. B-2, PDG. 2
2	REMOVE ESTIMATED COST OF CHLORINATOR	(69,590)	COMPANY SCH. B-2, PDG. 2
3	INCLUDE ACTUAL COST OF CHLORINATOR	85,699	DR # CSB 1.18
4	POST T/Y PLANT ADJUSTMENT	$ (8,597)	SUM LINES 1 THROUGH 3

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
RATE BASE ADJ #3 - ACCUMULATED DEFERRED INCOME TAXES (ADIT)

DOCKET NO. SW-02361A-05-0657
SCHEDULE MDC-5

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	ALGONQUIN ADIT ASSETS	$ 33,529,000	WAR ATTACHMENT A, PG. 43
2	ALGONQUIN ADIT LIABILITIES	(50,770,000)	WAR ATTACHMENT A, PG. 43
3	NET ADIT	(17,241,000)	LINE 1 + LINE 2
4	BLACK MOUNTAIN ALLOCATION	0.82%	NOTE (A)
5	BLACK MOUNTAIN ADIT	$ (141,921)	ALLOCATED ADIT
6	CONVERT TO US DOLLARS	1.1362	WALL STREET JOURNAL 2/28/2006
7	ALLOCATED ADIT BALANCE	$ (161,250)	LINE 5 x LINE 6

NOTES

(A) PURCHASE PRICE OF BLACK MOUNTAIN	6,782,000
ALGONQUIN TOTAL ASSETS	823,899,000
RATIO	0.82%

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
RATE BASE ADJ # 4 - WORKING CAPITAL

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	AVERAGE EXPENSE LAG	43.40	SCH. MDC-6 , PG. 2
2	AVERAGE REVENUE COLLECTION LAG	7.83	SCH. MDC-6, PG. 3
3	EXCESS EXPENSE OVER REVENUE LAG	(35.57)	LINE 2 - LINE 1
4	TOTAL EXPENSES	895,355	SCH. WAR-3
5	CASH WORKING CAPITAL REQUIREMENT	(87,253)	(LINE 3 x LINE 4)/365 DAYS
6	PER COMPANY	130,508	CO. SCH. B-5
7	IN(DE)CREASE IN WORKING CAPITAL	$ (217,761)	LINE 5 - LINE 6

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
RATE BASE ADJ # 4 - WORKING CAPITAL
CALCULATION OF EXPENSE LAGS

LINE NO.	DESCRIPTION	LAG DAYS	AMOUNT	DOLLAR DAYS
1	OPERATING EXPENSES	45	847,628	38,143,269
2	PURCHASED POWER	15	47,727	715,905
3	TOTAL		895,355	38,859,174
4	AVERAGE EXPENSE LAG	43.40		

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
RATE BASE ADJ # 4 - WORKING CAPITAL
CALCULATION OF REVENUE LAG

LINE NO.	PAYMENT DATE	SERVICE PERIOD MIDPOINT	(LEAD)/LAG DAYS	PAYMENT AMOUNT	DOLLAR DAYS
1	1/23/2004	1/15/2004	8	38	304
2	3/25/2004	3/15/2004	10	38	380
3	4/25/2004	4/15/2004	10	38	380
4	10/21/2004	10/15/2004	6	38	228
5	12/22/2004	12/15/2004	7	38	266
6	2/22/2004	2/14/2004	8	1,349	10,792
7	6/17/2004	6/15/2004	2	137	274
8	7/23/2004	7/15/2004	8	114	912
9	10/21/2004	10/15/2004	6	38	228
10	11/26/2004	11/15/2004	11	174	1,914
11	TOTAL			2,002	15,678
12	REVENUE (LEAD)/LAG DAYS			7.83	

BLACK MOUNTAIN SEWER CORPORATION

DOCKET NO. SW-02361A-05-0657

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

March 9, 2006

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and your qualifications in the field of utilities regulation.

A. Appendix I, which is attached to this testimony, describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Black Mountain Sewer Corporation's ("BMSC" or "Company") application requesting permanent rate relief ("Application"). BMSC's Application was filed with the Arizona Corporation Commission ("ACC" or "Commission") on September 16, 2005. The Company has chosen the period ended December 31, 2004 as the test year for this proceeding.

...

Q. Briefly describe BMSC.

A. BMSC provides wastewater and effluent water services to customers in the Town of Carefree, which is ten miles north of the City of Scottsdale in Maricopa County. During the test year, BMSC provided service to approximately 1,957 customers of which 1,836 were residential ratepayers and the remaining 121 were commercial establishments. The Company is a wholly owned subsidiary of Algonquin Water Resources of America, which, as described in the Company's Application, is an indirect wholly owned subsidiary of the Algonquin Power Income Fund ("Algonquin Fund" or "Parent"), a mutual fund which is listed on the Toronto Stock Exchange. Prior to being acquired by the Algonquin Fund, the Company operated under the name of Boulders Carefree Sewer.

Q. What effects does the ownership structure of BMSC have on the Company's operating expenses?

A. Certain expense items that are commonly found on the income statements of water and wastewater operations are absent on BMSC's income statement as a result of the ownership structure. This includes salaries and wage expense and income tax expense. The Company's parent charges BMSC contractual service fees for items such as professional services, labor, administrative & accounting staff, testing services and management at the local and corporate levels. Consequently, the Company's parent has a large measure of control over the amounts that are charged for contractual service expenses. Given the fact that the Company's parent has direct control on any markup for performing these services, the potential exists to manipulate BMSC's bottom line operating income.

Q. What issues will you address in your direct testimony?

A. I will address the issues related to RUCO's recommended levels of operating revenue, operating expense and RUCO's recommended rate design for BMSC.

Q. Will you also address the issues related to RUCO's recommended rate base in this proceeding?

A. No that aspect of the case will be handled by RUCO witness Marylee Diaz Cortez, CPA.

Q. Did you perform a cost of capital analysis to determine a recommended rate of return on the Company's invested capital?

A. Yes, I did. I have also filed, under separate cover, direct testimony on the cost of capital issues associated with this proceeding.

...

Q. Please describe how you conducted your analysis of BMSC's Application.

A. I reviewed BMSC's Application and analyzed various accounting records that were provided to RUCO by the Company. During the course of my audit, I also obtained copies of various documents available on the Internet and copies of documents that are kept on file at the ACC. Other pertinent information and source documents were collected through a series of written data requests submitted to the Company. After compiling the aforementioned information and materials, I performed an analysis that provided additional insight into the Company's required revenue and rate design proposals. The recommendations on operating revenue, operating expenses and rate design in this testimony are based on the results of my analysis.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-13.

Q. Does your silence on any of the issues or matters addressed in the Company's Application constitute RUCO's acceptance of the Company's position on such issues or matters?

A. No, it does not.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the recommendations and adjustments that you address in your testimony on operating revenues and operating expenses.

A. My testimony will address the following issues:

Operating Revenue and Expense:

Remove Operating Lease Expense – This adjustment removes $189,622 in pro-forma expense associated with an operating lease payment. The adjustment is part of RUCO witness Marylee Diaz Cortez's recommendation that the purchased treatment capacity should appropriately be reflected as an asset, as opposed to an operating lease.

Capitalize Test Year Expense Items – This adjustment capitalizes $6,693 in costs related to an operating agreement between the Company and the Town of Carefree, and the installation of safety equipment, during the test year.

Normalize Management Fees – This adjustment normalizes management fees based on the amounts charged during the last five months of the test year.

Remove Long-Distance Charges – The adjustment removes certain long-distance phone charges unrelated to BMSC operations, which were incorrectly included in the Company-proposed level of test year miscellaneous expense.

Amortization of Rate Case Expense – This adjustment reflects RUCO's preliminary estimated rate case expense for the instant proceeding. RUCO's final estimate will be presented during the evidentiary hearing after the majority of the Company's rate case expense has been tabulated.

Depreciation & Amortization Expense – This adjustment calculates the Company's depreciation and amortization expense on a going forward basis. The adjustment also includes the 20-year amortization of the purchased treatment capacity from the City of Scottsdale.

Property Tax Expense – This adjustment calculates the appropriate level of property tax expense using the Arizona Department of Revenue's ("ADOR") approved formula for calculating water utilities' property tax liabilities.

Income Tax Expense – This adjustment calculates the appropriate level of federal and state income tax expense given RUCO's recommended level of operating income.

Rate Design:

RUCO is recommending that the current rate design be retained, and that the current charges be revised in order to generate RUCO's recommended level of operating revenue.

REVENUE REQUIREMENTS

Q. Please summarize the results of your analysis of BMSC's revenue requirements.

A. Based on the results of my audit, I am recommending that the level of revenue be increased by no more than $5,470 for BMSC (Schedule WAR-1). RUCO's supporting original cost rate base ("OCRB") detail (Schedule MDC-1) is based on the original costs that BMSC has agreed to accept as the Company's fair value rate base. Schedule WAR-1 displays my recommended adjusted operating income of $125,730. Schedule WAR-2 includes supporting detail for my operating income figures.

OVERVIEW OF THE FILING

Q. Please describe BMSC's rate application.

A. BMSC is requesting a rate increase of $163,279 or a 13.52 percent increase over adjusted operating revenues of $1,207,740 recorded during the test year.

The Company is also seeking increases in a number of operating expense items which include purchased wastewater treatment, purchased power, chemicals, regulatory expense and payments on a Company-proposed operating lease as well as increases in the Company's depreciation expense, and taxes. As I explained earlier in my testimony, three of the Company's operating expenses associated with professional services, testing and other services, are provided contractually through Algonquin Water Services, a subsidiary of Algonquin Water Resources of America, a company which has a large measure of control over the final amounts billed to BMSC.

OPERATING INCOME

Operating Adjustment #1 – Remove Operating Lease Expense

Q. Why have you removed the $189,622 Scottsdale Capacity (Operating Lease) expense that the Company is seeking?

A. The removal of the Company-proposed Scottsdale Capacity (Operating Lease) expense is a result of the rate base adjustments being recommended by RUCO witness Marylee Diaz Cortez, CPA. Ms. Diaz Cortez is recommending that purchased treatment capacity from the City of Scottsdale be treated as a utility asset, as opposed to an operating lease, and be included in rate base.

Q. What specifically does your adjustment remove?

A. The adjustment removes the full amount of the Company-proposed operating lease expense, which includes debt service on two inter-company loans. In addition to the normal debt service payments of principal and interest, the Company's consultant has also included a gross-up adjustment on the principal portion of the loan. The loans have been booked as an inter-company payable, and appear as a liability (i.e. payables to associated companies) on the Company's balance sheet.

Q. Will your adjustment provide BMSC with the opportunity to recover the loan proceeds that have been booked as an inter-company payable?

A. Yes it will. Under Ms. Diaz Cortez's rate base recommendation, the Company will fully recover the inter-company loans. The purchased treatment capacity will be treated as a utility asset and included in rate base, which will entitle the Company to earn the Commission-approved rate of return on it. BMSC will fully recover the principal portion of the loan through RUCO's recommended level of depreciation and amortization expense and will have the opportunity to recover the interest associated with the loan as a below-the-line expense that will reduce the Company's income tax liability. Under Ms. Diaz Cortez's rate base recommendation, there is no need for the Company consultant's gross-up adjustment on the principal portion of the loans since the loans, and the asset (i.e. Scottsdale treatment capacity) that were purchased by BMSC will be treated as they would under normal ratemaking practice. As I will explain in more detail in my cost of capital testimony, the inter-company loans will be treated as long-term debt in the Company's capital structure, as opposed to the Company-proposed capital structure of 100 percent common equity.

Operating Adjustment #2 – Capitalize Test Year Expense Items

Q. Please explain your adjustment that capitalizes certain test year expense items.

A. My adjustment capitalizes $6,693 in test year expenses related to two separate test year items. The first item concerns $3,228 in legal expenses related to an operating agreement between the Company and the Town of Carefree. BMSC stated that negotiations on the matter were coming to a close, and that the Company expected the agreement to be approved in February 2006. RUCO has capitalized the legal costs booked during the test year and is recommending that the capitalized amount of $3,228 be recorded in Account No. 352, Franchises, as a non-depreciable plant-in-service item. The second item deals with the $3,465 cost of purchasing, installing, and providing training on confined space entry and rescue equipment during the test year. RUCO is recommending that the $3,465 amount also be treated as plant-in-service and recorded in Account No. 389, Other Plant and Misc. Equipment. The cost of both items exceeded the Company's $250 threshold for determining what should be expensed and what should be capitalized.

Operating Adjustment #3 – Normalize Management Fees

Q. What does your $24,500 adjustment to the Company's Contractual Services – Professional expense represent?

A. The negative $24,500 adjustment represents the difference between the $18,000 normalized level of management fees that RUCO is recommending, and the $42,500 amount of Company adjusted management fees that were booked into BMSC's general ledger during the test year ($18,000 normalized management fee expense - $42,500 booked management fee expense = ($24,500) RUCO adjustment). This can be viewed in detail in Schedule WAR-4.

Q. How did you arrive at RUCO's $18,000 recommended level of management fee expense for BMSC?

A. I normalized the amount of management fees being charged to BMSC in order to arrive at RUCO's recommended level of management fee expense of $18,000 per year. The normalization is based on the amount of management fees that were charged to BMSC during the last five months of the test year. As recorded in the Company's test year general ledger, BMSC was billed $1,500 for August through December of 2004. This works out to an annual level of expense of $18,000 ($1,500 per month X 12 months = $18,000). The Company had charged $5,000 per month from January through October, but made adjusting entries of $3,500 for the months of August, September and October. These adjusting entries lowered the $5,000 per month management fee charged during August, September and October to the $1,500 amount charged during November and December.

Q. Has the Company proposed a similar normalization adjustment?

A Yes. The Company performed a similar normalization in order to arrive at its test year level of $156,742 in contract operating fees charged to BMSC.

Operating Adjustment #4 – Remove Long-Distance Charges

Q. Please explain RUCO's adjustment, which removes $520 from the Company-proposed level of miscellaneous expense.

A. As exhibited in Schedule WAR-5, the adjustment removes long-distance phone charges for calls made to various locations in Texas. The Company stated that the calls were incorrectly included in the Company-proposed test year level of miscellaneous expense.

Operating Adjustment #5 - Depreciation and Amortization Expense

Q. Have you calculated depreciation and amortization expense?

A. Yes. The calculation is exhibited in Schedule WAR-6. I have calculated a full year of depreciation and amortization expense based on RUCO's recommended levels of test year plant balances.

Q. How did you calculate your recommended level of depreciation and amortization of contributions in aid of construction ("CIAC") expense for BMSC?

A. As exhibited in Schedule WAR-6, my recommended level of depreciation expense was calculated by applying the Company-proposed rates of depreciation to RUCO's adjusted plant account balances. As noted earlier, my recommended figure of $186,655 also includes amortization expense on the purchased treatment capacity. My recommended level of amortization of CIAC was calculated by applying the Company-proposed 4.0322 percent composite rate of amortization to RUCO's adjusted level of CIAC in order to arrive at the proper amount of amortization of CIAC to be deducted from the Company's depreciation expense.

Operating Adjustment #6 - Property Tax Expense

Q. Is RUCO recommending an adjustment to the Company-proposed levels of property tax expense for BMSC?

A. Yes. My adjustment, exhibited in Schedule WAR-7, decreases the Company-proposed level of property tax expense by $10,335. The property tax calculation was made using the currently effective ADOR formula.

...

Q. Please explain the basis of RUCO's adjustment to property tax expense for BMSC.

A. In a number of cases argued before the Commission, RUCO has consistently maintained that the use of historical revenues in the ADOR formula, as the formula dictates, is the best estimate of future property taxes. RUCO is thoroughly convinced that this is the proper way to measure property tax, now that actual post-test year property tax is known and comparisons can be made.

In this case, the comparison of actual property tax for 2005 to the estimates using the ADOR recommended revenues and the Company's recommended revenues illustrates that the use of ADOR's formula is far more accurate.

Q. How does the methodology used by BMSC vary from the ADOR formula?

A. BMSC has varied the ADOR formula by using, for valuation purposes, two years of adjusted revenues plus one year of Company-proposed revenues. The property tax formula, as prescribed by ADOR's memo of January 3, 2001, determines the Full Cash Value ("FCV") of water utilities, for property tax purposes, by multiplying the average of the three previous years of reported gross revenues of the Company by a factor of two.

Q. What is the result of BMSC's calculation of the property tax pro-forma adjustment?

A. The result is a FCV, which will likely allow BMSC to over-earn based on the Company's expected property tax expense. Among the goals of ADOR was to arrive at a forward looking valuation formula that would produce predictable figures, logical results and minimize the tax impact from the previous year.

Q. Can you provide evidence that demonstrates that RUCO's calculation is more appropriate?

A. Yes, I can. The evidence in this case attests to the accuracy of RUCO's calculation. Using ADOR's formula, RUCO recommended property tax expense for 2005 is $35,410 and the Company's requested level for property tax expense is $45,745. By comparison, BMSC's actual property tax assessed by ADOR for 2005 is $31,949, thus the ADOR formula results in a more accurate level of property tax expense than does the Company's "modified" formula.

It is unlikely that the Company will generate revenues consistent with its estimates in the near future. BMSC would be over-collecting the property tax expense for a number of years before the actual assessment would catch up to the Company's 2005 projected revenue. In the meantime, BMSC will be recovering the Company's property tax expense based on an inflated revenue projection.

Q. When will BMSC pay the property tax impacted by the changes in revenues approved in this rate case?

A. Assuming that rates go into effect in mid 2006, it will not be until the end of 2007 before BMSC will have one full year of operating revenues at the new rates.

The Company will pay property taxes for the tax-year 2007 semi-annually, with the first payment coming due in October 2007, and the final payment due in 2008.

Q. What action is RUCO taking to promote its position and establish acceptance of its recommendation on how to implement the ADOR formula?

A. Since the property tax formula, as prescribed by ADOR, was in a memo dated January 3, 2001, and requires the use of two historical years of revenue, the full ramification of the ADOR formula will not take effect until the 2005 assessment with that property tax expense final payment due in early 2006.

Therefore, RUCO is continuing to gather evidence on the appropriateness of the ADOR formula to accurately project future property taxes for ratemaking purposes. RUCO asserts the data will further demonstrate that its property tax arguments are correct. For these reasons RUCO believes that the Commission should adopt my recommended level of property tax expense.

Operating Adjustment #7 - Income Tax Expense

Q. Have you calculated income tax expense based on RUCO's recommended adjusted operating income for BMSC?

A. Yes. This adjustment is shown on Schedules WAR-8. The adjustment uses the synchronized interest method for calculating the level of interest expense to be deducted from income taxes.

Operating Adjustment #8 - Amortization of Rate Case Expense

Q. Please explain your adjustments to rate case expense for BMSC.

A. At this time I am not proposing an adjustment to the Company's requested level of rate case expense.

Q. Does this mean RUCO has adopted the Company's estimates in full?

A. No. RUCO has reviewed the amount of rate case expense billed to date and has decided that the prudent approach would be to wait until a final figure can be accurately calculated and compared to the Company's request. RUCO will present a final estimate on rate case expense amortization during the evidentiary hearing.

RATE DESIGN

Q. Have you reviewed BMSC's proposed rate design?

A. Yes. Schedule WAR-10 presents a comparison of BMSC's present rates, the Company-proposed rates and RUCO's recommended rates.

Q. Is BMSC's present type of rate design typical of what the Commission generally approves for wastewater providers?

A. No. In the wastewater cases that I have been involved with, the Commission has generally approved a flat monthly charge for all of the customers on the system.

Q. How is BMSC's present rate design different?

A. BMSC's rate design is different because the rates were based on wastewater flows established by the Arizona Department of Environmental Quality ("ADEQ")[1]. The Company's commercial customers ("Standard Rate Customers") are subject to a per gallon per day rate and a select number of commercial customers ("Special Rate Customers") pay a monthly charge that is based on a predetermined level of gallons per day for the type of business establishment that they operate. The Company's residential customers are subject to the more typical flat monthly charge that I described above, however, it too was also based on a flow level

[1] The commercial, residential and average daily wastewater flows, for Special Rate Customers, that BMSC's rates are based on were set forth in Engineering Bulletin No. 12, published in June of 1989 by the Arizona Department of Environmental Quality.

established by ADEQ. BMSC also produces and sells effluent water at a rate that is based on the number of acre-feet purchased.

Q. What type of rate design is BMSC proposing?

A. BMSC is proposing that the present type of rate design be retained and has only made adjustments to the monthly charges to generate the Company-proposed level of revenue for wastewater service.

Q. Is RUCO recommending any departure from the present type of rate design?

A. No. RUCO is also recommending that the current type of rate design be retained and, like the Company, has only made adjustments to the monthly charges in order to generate RUCO's recommended level of revenue. RUCO has applied its recommended percentage of increase in revenue to all of the present rates and charges in order to arrive at its recommended rates and charges for BMSC.

Q. What is RUCO's recommended flat monthly charge for residential customers?

A. RUCO is recommending a flat monthly charge of $38.04 for residential customers, which is $0.04 a month higher than the present flat monthly charge of $38.00.

Q. What is RUCO's recommended rate for the commercial Standard Rate Customers?

A. RUCO is also recommending a rate of $0.152539, which is $0.000179 higher than the present rate of $0.152360. As can be seen in Schedule WAR-11, this results in a typical monthly bill, at the 570-gallon median level of consumption, of $86.95, which is an increase of $0.10 over the present monthly bill of $86.85.

Q. For the Standard Rate Customers, did you prepare a schedule that shows, at various levels of consumption, the resulting monthly bills under present and proposed rates?

A. Yes. This information is exhibited in Schedule WAR-12, which also displays the difference in dollars and percent between the present rates and RUCO's proposed rates for BMSC.

Q. What are RUCO's recommended rates for the commercial Special Rate Customers?

A. As can be seen in Schedule WAR-11, RUCO is recommending that the present predetermined consumption levels established by ADEQ be retained. RUCO's recommended monthly charges for the Special Rate Customers range from $29.25 to $3,479.32 depending on the type of business establishment.

Q. Did RUCO annualize the billing determinants based on the Company's end of test year customer count?

A. Yes. RUCO has adopted the Company's annualized customer count and has applied that to the test year billing determinants in order to arrive at RUCO's recommended level of operating revenue from flat rate wastewater sales.

Q. Will your rate design provide BMSC with the level of revenue recommended by RUCO?

A. Yes, it will. Based on the test year billing determinants as adjusted (i.e. annualized) my recommended rate design will generate RUCO's recommended level of revenue for BMSC. This can be viewed in Schedule WAR-13.

Q. Does this conclude your direct testimony on BMSC?

A. Yes, it does.

Appendix 1

Qualifications of William A. Rigsby

Qualifications of William A. Rigsby

EDUCATION:	University of Phoenix Master of Business Administration, Emphasis in Accounting, 1993
	Arizona State University College of Business Bachelor of Science, Finance, 1990
	Mesa Community College Associate of Applied Science, Banking and Finance, 1986
	Michigan State University Institute of Public Utilities N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999
	Florida State University Center for Professional Development & Public Service N.A.R.U.C. Annual Western Utility Rate School, 1996
EXPERIENCE:	Public Utilities Analyst V Residential Utility Consumer Office Phoenix, Arizona April 2001 – Present
	Senior Rate Analyst Accounting & Rates - Financial Analysis Unit Arizona Corporation Commission, Utilities Division Phoenix, Arizona July 1999 – April 2001
	Senior Rate Analyst Residential Utility Consumer Office Phoenix, Arizona December 1997 – July 1999
	Utilities Auditor II and III Accounting & Rates – Revenue Requirements Analysis Unit Arizona Corporation Commission, Utilities Division Phoenix, Arizona October 1994 – November 1997
	Revenue Auditor II Arizona Department of Revenue Corporate Income Tax Audit Unit Phoenix, Arizona November 1993 – October 1994
	Tax Examiner Technician I Arizona Department of Revenue Transaction Privilege Tax Audit Unit Phoenix, Arizona July 1991 – November 1993

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase

BLACK MOUNTAIN SEWER CORPORATION
DOCKET NO. SW-02361A-05-0657
TABLE OF CONTENTS TO SCHEDULES WAR

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
REVENUE REQUIREMENTS

LINE NO.	DESCRIPTION	(A) COMPANY REQUESTED	(B) RUCO RECOMMENDED
1	ADJUSTED RATE BASE	$ 887,449	$ 1,372,834
2	ADJUSTED OPERATING INCOME	(14,233)	125,730
3	CURRENT RATE OF RETURN (L2 / L1)	-1.60%	9.16%
4	REQUIRED RATE OF RETURN	11.00%	9.45%
5	REQUIRED OPERATING INCOME (L4 * L1)	97,619	129,733
6	OPERATING INCOME DEFICIENCY (L5 - L2)	111,852	4,003
7	GROSS REVENUE CONVERSION FACTOR	1.4598	1.3663
8	GROSS REVENUE INCREASE	$ 163,279	$ 5,470
9	CURRENT REVENUES T/Y ADJUSTED	1,207,740	1,207,740
10	PROPOSED ANNUAL REVENUE (L8 + L9)	1,371,019	1,213,210
11	PERCENTAGE AVERAGE INCREASE	13.52%	0.45%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE A-1
COLUMN (B): SCHEDULE WAR-1, PG. 2, MDC-1, WAR-2 AND WAR-9

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	REVENUE	1.0000	
2	UNCOLLECTIBLES	0.0000	COMPANY SCH. C-3
3	SUB-TOTAL	1.0000	LINE 1 - LINE 2
4	LESS: TAX RATE	26.81%	NOTE (a)
5	TOTAL	0.7319	LINE 3 - LINE 4
6	REVENUE CONVERSION FACTOR	1.36630	LINE 1/LINE 5

NOTE (a):
CALCULATION OF EFFECTIVE TAX RATE

OPERATING INCOME BEFORE TAXES	100.00%
LESS: ARIZONA STATE TAX	6.97%
TAXABLE INCOME FEDERAL	93.03%
TIMES: FEDERAL INCOME TAX RATE	21.33%
SUBTOTAL	19.84%
ADD STATE TAX RATE	26.81%
LINE 3 ABOVE	100.00%
EFFECTIVE TAX RATE	26.81%

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING INCOME - TEST YEAR AND RUCO PROPOSED

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-2

LINE NO.	DESCRIPTION	(A) COMPANY TEST YEAR AS FILED	(B) RUCO TEST YEAR ADJUSTMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO RECOMMENDED
1	REVENUES - WASTEWATER:					
2	FLAT RATE REVENUES	$ 1,191,268	$ -	$ 1,191,268	$ 5,470	$ 1,196,738
3	MEASURED REVENUES	-	-			
4	OTHER WASTEWATER REVENUES	16,472	-	16,472		16,472
5	TOTAL OPERATING REVENUES	$ 1,207,740	$ -	$ 1,207,740	$ 5,470	$ 1,213,210
6	OPERATING EXPENSES:					
7	SALARIES AND WAGES	$ -	$ -	$ -	$ -	$ -
8	PURCHASED WASTEWATER TREATMENT	162,082	-	162,082		162,082
9	SLUDGE REMOVAL EXPENSE	981	-	981		981
10	PURCHASED POWER	47,727	-	47,727		47,727
11	FUEL FOR POWER PRODUCTION	-	-	-		-
12	CHEMICALS	76,612	-	76,612		76,612
13	MATERIALS AND SUPPLIES	30,420	-	30,420		30,420
14	CONTRACTUAL SERVICES - PROFESSIONAL	171,683	(27,728)	143,955		143,955
15	CONTRACTUAL SERVICES - TESTING	11,000	-	11,000		11,000
16	CONTRACTUAL SERVICES - OTHER	226,595	-	226,595		226,595
17	RENTS	10,825	-	10,825		10,825
18	TRANSPORTATION EXPENSES	4,870	-	4,870		4,870
19	INSURANCE - GENERAL LIABILITY	16,204	-	16,204		16,204
20	REGULATORY COMMISSION EXPENSE	30,000	-	30,000		30,000
21	MISCELLANEOUS EXPENSE	77,401	(3,985)	73,416		73,416
22	SCOTTSDALE CAPACITY (OPERATING LEASE)	189,622	(189,622)	-		-
23	DEPRECIATION & AMORTIZATION	126,749	59,906	186,655		186,655
24	TAXES OTHER THAN INCOME	-	-	-		-
25	PROPERTY TAXES	45,745	(10,335)	35,410		35,410
26	FEDERAL & STATE INCOME TAXES	(6,544)	31,801	25,257	1,466	26,724
27	TOTAL OPERATING EXPENSES	$ 1,221,973	$ (139,962)	$ 1,082,010	$ 1,466	$ 1,083,477
28	NET INCOME	$ (14,233)	$ 139,962	$ 125,730	$ 4,003	$ 129,733

REFERENCES:
COLUMN (A): CO. SCH. C-1
COLUMN (B): SCH. WAR-3
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): SCH. WAR-1, PAGE 2 OF 2
COLUMN (E): COLUMN (C) + COLUMN (D)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
SUMMARY OF OPERATING ADJUSTMENTS

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-3

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
LINE NO.	DESCRIPTION	COMPANY PROPOSED	ADJ. #1	ADJ. #2	ADJ. #3	ADJ. #4	ADJ. #5	ADJ. #6	ADJ. #7	RUCO ADJUSTED
1	REVENUES - WASTEWATER:									
2	FLAT RATE REVENUES	$ 1,191,268	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,191,268
3	MEASURED REVENUES	-								-
4	OTHER WASTEWATER REVENUES	16,472								16,472
5	TOTAL OPERATING REVENUES	$ 1,207,740	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,207,740
6	OPERATING EXPENSES:									
7	SALARIES AND WAGES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	PURCHASED WASTEWATER TREATMENT	162,082								162,082
9	SLUDGE REMOVAL EXPENSE	981								981
10	PURCHASED POWER	47,727								47,727
11	FUEL FOR POWER PRODUCTION	-								-
12	CHEMICALS	76,612								76,612
13	MATERIALS AND SUPPLIES	30,420								30,420
14	CONTRACTUAL SERVICES - PROFESSIONAL	171,683		(3,228)	(24,500)					143,955
15	CONTRACTUAL SERVICES - TESTING	11,000								11,000
16	CONTRACTUAL SERVICES - OTHER	226,595								226,595
17	RENTS	10,825								10,825
18	TRANSPORTATION EXPENSES	4,870								4,870
19	INSURANCE - GENERAL LIABILITY	16,204								16,204
20	REGULATORY COMMISSION EXPENSE	30,000								30,000
21	MISCELLANEOUS EXPENSE	77,401		(3,465)		(520)				73,416
22	SCOTTSDALE CAPACITY (OPERATING LEASE)	189,622	(189,622)							-
23	DEPRECIATION & AMORTIZATION	126,749					59,906			186,655
24	TAXES OTHER THAN INCOME	-								-
25	PROPERTY TAXES	45,745						(10,335)		35,410
26	FEDERAL & STATE INCOME TAXES	(6,544)							31,801	25,257
27	TOTAL OPERATING EXPENSES	$ 1,221,973	$ (189,622)	$ (6,693)	$(24,500)	$ (520)	$ 59,906	$ (10,335)	$ 31,801	$ 1,082,010
28	NET INCOME	$ (14,233)	$ 189,622	$ 6,693	$ 24,500	$ 520	$ (59,906)	$ 10,335	$ (31,801)	$ 125,730

ADJUSTMENT #:	REFERENCE:
1. REMOVE OPERATING LEASE EXPENSE	DIRECT TESTIMONY - WAR
2. CAPITALIZE TEST YEAR EXPENSE ITEMS	DIRECT TESTIMONY - WAR
3. NORMALIZE MANAGEMENT FEES	SCHEDULE WAR-4
4. REMOVE LONG-DISTANCE CHARGES	SCHEDULE WAR-5
5. DEPRECIATION AND AMORTIZATION EXPENSE	SCHEDULE WAR-6
6. PROPERTY TAX EXPENSE	SCHEDULE WAR-7
7. INCOME TAX EXPENSE	SCHEDULE WAR-8

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJUSTMENT #3 - NORMALIZE MANAGEMENT FEES

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-4

LINE NO.	JOURNAL ENTRY #	SERIES	TRANSACTION DATE	ACCOUNT NUMBER	NARUC #	ACCOUNT DESCRIPTION	AMOUNT	REFERENCE
1	19737	PURCHASING	01/29/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	$ 5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
2	20504	PURCHASING	02/29/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
3	21177	PURCHASING	03/30/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
4	21813	PURCHASING	04/30/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
5	22484	PURCHASING	05/31/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
6	23363	PURCHASING	06/30/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
7	23771	PURCHASING	07/29/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
8	24163	PURCHASING	08/31/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
9	24430	PURCHASING	09/30/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
10	24636	PURCHASING	10/29/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	5,000	BMSC GENERAL LEDGER PAGE 118 OF 126
11	24745	PURCHASING	10/31/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	(3,500)	BMSC GENERAL LEDGER PAGE 118 OF 126
12	24746	PURCHASING	10/31/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	(3,500)	BMSC GENERAL LEDGER PAGE 118 OF 126
13	24747	PURCHASING	10/31/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	(3,500)	BMSC GENERAL LEDGER PAGE 118 OF 126
14	24828	PURCHASING	01/01/00	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	1,500	BMSC GENERAL LEDGER PAGE 119 OF 126
15	24943	PURCHASING	12/15/04	8100-2-0200-69-5200-0023	736.8	CONTRACTUAL SERVICES - MANAGEMENT FEE	1,500	BMSC GENERAL LEDGER PAGE 119 OF 126
16								
17	TOTAL GENERAL LEDGER ENTRIES FOR MANAGEMENT FEES						$ 42,500	SUM OF LINES 1 THRU 15
18								
19	RUCO NOMALIZED LEVEL OF MANAGEMENT FEE EXPENSE						$ 18,000	LINE 15 X 12 MONTHS
20								
21	RUCO ADJUSTMENT						$ (24,500)	LINE 19 - LINE 17

REFERENCES:
ACC STAFF DATA REQUEST CSB 1.1

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJUSTMENT #4 - REMOVE LONG-DISTANCE CHARGES

LINE NO.	CALL NUMBER	CALL DATE	CALL TIME	LOCATION CALLED	PHONE NUMBER CALLED	PHONE NUMBER BILLED TO	NUMBER OF MINUTES	CALL TYPE	RATE PERIOD	AMOUNT BILLED
1	14	01/07/04	10:12 AM	GRAND PRARI, TX	214-236-6371	480-575-1607	1	DDC	DAY	$ 0.99
2	30	01/07/04	11:08 AM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	1.98
3	31	01/07/04	4:01 PM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	1.98
4	18	01/09/04	8:46 AM	TYLER, TX	903-530-6364	480-575-1607	1	DDC	DAY	0.99
5	19	01/09/04	8:58 AM	TYLER, TX	903-581-5930	480-575-1607	4	DDC	DAY	3.96
6	19	01/12/04	10:37 AM	TYLER, TX	903-581-5930	480-575-7303	3	DDC	DAY	2.97
7	21	01/13/04	8:17 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
8	22	01/13/04	9:45 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
9	20	01/13/04	9:15 AM	TROUP, TX	903-842-3151	480-575-7303	2	DDC	DAY	1.98
10	1	01/14/04	12:48 PM	TYLER, TX	903-534-6009	480-575-1607	4	DDC	DAY	3.96
11	2	01/14/04	1:04 PM	TYLER, TX	903-534-6009	480-575-1607	6	DDC	DAY	5.94
12	3	01/14/04	1:13 PM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
13	4	01/16/04	8:59 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
14	5	01/16/04	12:00 AM	TYLER, TX	903-534-6009	480-575-1607	1	DDC	DAY	0.99
15	44	01/19/04	2;41 PM	TYLER, TX	903-509-4713	480-575-1845	4	DDC	DAY	3.96
16	21	01/19/04	2:46 PM	TYLER, TX	903-581-5930	480-575-7303	1	DDC	DAY	0.99
17	10	01/20/04	3:46 PM	TYLER, TX	903-534-6009	480-575-1607	1	DDC	DAY	0.99
18	46	01/20/04	3:47 PM	TYLER, TX	903-509-4713	480-575-1845	3	DDC	DAY	2.97
19	11	01/21/04	9:42 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
20	12	01/22/04	8:49 AM	TYLER, TX	903-534-6009	480-575-1607	2	DDC	DAY	1.98
21	13	01/22/04	1:24 PM	TROUP, TX	903-842-3151	480-575-1607	4	DDC	DAY	3.96
22	14	01/23/04	9:32 AM	TYLER, TX	903-561-3040	480-575-1607	1	DDC	DAY	0.99
23	15	01/23/04	10:20 AM	TYLER, TX	903-581-5930	480-575-1607	5	DDC	DAY	4.95
24	16	01/23/04	10:28 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
25	17	01/23/04	1:02 PM	TYLER, TX	903-561-9527	480-575-1607	3	DDC	DAY	2.97
26	1	01/23/04	1:22 PM	TYLER, TX	903-561-8325	480-575-1845	1	DDC	DAY	0.99
27	19	01/27/04	8:49 AM	TYLER, TX	903-534-6009	480-575-1607	1	DDC	DAY	0.99
28	21	01/27/04	9;17 AM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
29	5	01/27/04	4:31 PM	TYLER, TX	903-561-8325	480-575-1845	1	DDC	DAY	0.99
30	22	01/27/04	2:03 PM	TYLER, TX	903-561-3040	480-575-7303	1	DDC	DAY	0.99
31	22	01/29/04	2:59 PM	BULLARD, TX	903-894-6073	480-575-1607	2	DDC	DAY	1.98
32	23	01/29/04	3:14 PM	KATY, TX	281-395-5321	480-575-1607	14	DDC	DAY	13.86
33	9	01/29/04	9:54 AM	TYLER, TX	903-581-8251	480-575-1845	1	DDC	DAY	0.99
34	10	01/29/04	9:55 AM	TYLER, TX	903-581-8251	480-575-1845	4	DDC	DAY	3.96
35	24	01/30/04	1:07 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
36	26	02/03/04	8:43 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
37	27	02/03/04	2:23 PM	TYLER, TX	903-579-9731	480-575-1607	7	DDC	DAY	6.93
38	13	02/03/04	9:24 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
39	14	02/04/04	4;03 PM	TYLER, TX	903-579-9732	480-575-1845	1	DDC	DAY	0.99
40	10	02/06/04	8:13 AM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	1.98
41	11	02/06/04	8:15 AM	TYLER, TX	903-534-6030	480-575-1845	3	DDC	DAY	2.97
42	14	02/17/04	3:14 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
43	19	02/20/04	1:27 PM	TYLER, TX	903-581-5930	480-575-1607	5	DDC	DAY	4.95
44	1	02/24/04	10:14 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
45	24	02/24/04	9:18 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
46	20	02/24/04	10:17 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
47	26	02/24/04	12:51 PM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	1.98
48	4	02/25/04	10:15 AM	KATY, TX	281-395-5321	480-575-1607	8	DDC	DAY	7.92
49	27	02/25/04	2:32 PM	TYLER, TX	903-593-2542	480-983-1294	1	DDC	DAY	0.11
50	8	03/01/04	3:36 PM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJUSTMENT #4 - REMOVE LONG-DISTANCE CHARGES

LINE NO.	CALL NUMBER	CALL DATE	CALL TIME	LOCATION CALLED	PHONE NUMBER CALLED	PHONE NUMBER BILLED TO	NUMBER OF MINUTES	CALL TYPE	RATE PERIOD	AMOUNT BILLED
1	9	03/02/04	12:05 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	$ 0.99
2	35	03/03/04	10:18 AM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	1.98
3	17	03/16/04	3:02 PM	VAN, TX	903-963-5897	480-575-1607	24	DDC	DAY	23.76
4	21	03/16/04	9:45 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
5	18	03/17/04	3:47 PM	TYLER, TX	903-521-5016	480-575-1607	5	DDC	DAY	4.95
6	22	03/17/04	11:53 AM	TYLER, TX	903-509-9007	480-575-1845	1	DDC	DAY	0.99
7	37	03/18/04	1:39 PM	KATY, TX	281-395-5321	480-575-7303	1	DDC	DAY	0.99
8	38	03/18/04	1:39 PM	KATY, TX	281-395-5321	480-575-7303	3	DDC	DAY	2.97
9	19	03/29/04	9:40 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
10	20	03/29/04	9:43 AM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
11	22	03/31/04	9:34 AM	KATY, TX	281-395-5321	480-575-1607	1	DDC	DAY	0.99
12	1	04/02/04	10:17 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
13	2	04/02/04	4:11 PM	TYLER, TX	903-581-4100	480-575-1607	2	DDC	DAY	1.98
14	40	04/05/04	12:00 AM	TYLER, TX	903-581-5930	480-575-7303	1	DDC	DAY	0.99
15	41	04/06/04	2:56 PM	BULLARD, TX	903-894-6453	480-575-7303	1	DDC	DAY	0.99
16	11	05/10/04	8:50 AM	AUSTIN, TX	512-239-3745	480-575-1607	13	DDC	DAY	12.87
17	12	05/10/04	9:10 AM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
18	13	05/10/04	9:11 AM	HALLSVILLE, TX	903-668-4133	480-575-1607	1	DDC	DAY	0.99
19	15	05/10/04	11:33 AM	AUSTIN, TX	512-239-3745	480-575-1607	2	DDC	DAY	1.98
20	16	05/10/04	11:55 AM	AUSTIN, TX	512-239-3745	480-575-1607	2	DDC	DAY	1.98
21	31	05/10/04	9:17 AM	AUSTIN, TX	512-329-4562	480-575-1845	12	DDC	DAY	11.88
22	32	05/10/04	10:27 AM	AUSTIN, TX	512-239-4562	480-575-1845	6	DDC	DAY	5.94
23	33	05/10/04	11:41 AM	AUSTIN, TX	512-239-0134	480-575-1845	6	DDC	DAY	5.94
24	34	05/10/04	11:48 AM	AUSTIN, TX	512-239-0134	480-575-1845	6	DDC	DAY	5.94
25	19	05/11/04	9:04 AM	HALLSVILLE, TX	903-668-4133	480-575-1607	1	DDC	DAY	0.99
26	20	05/11/04	10:46 AM	KATY, TX	281-395-5321	480-575-1607	1	DDC	DAY	0.99
27	21	05/11/04	10:51 AM	HALLSVILLE, TX	903-668-4133	480-575-1607	1	DDC	DAY	0.99
28	22	05/11/04	2:50 PM	KATY, TX	281-395-5321	480-575-1607	2	DDC	DAY	1.98
29	36	05/11/04	8:24 AM	AUSTIN, TX	512-239-0134	480-575-1845	1	DDC	DAY	0.99
30	37	05/11/04	9:28 AM	AUSTIN, TX	512-239-0134	480-575-1845	4	DDC	DAY	3.96
31	38	05/11/04	10:59 AM	AUSTIN, TX	512-239-0134	480-575-1845	3	DDC	DAY	2.97
32	4	05/19/04	9:36 AM	KATY, TX	281-395-5321	480-575-1607	1	DDC	DAY	0.99
33	8	05/19/04	3:26 PM	KATY, TX	281-395-5321	480-575-1607	1	DDC	DAY	0.99
34	9	05/20/04	2:21 PM	TYLER, TX	903-520-2906	480-575-1607	1	DDC	DAY	0.99
35	10	05/20/04	4:17 PM	TYLER, TX	903-520-2906	480-575-1607	3	DDC	DAY	2.97
36	48	05/20/04	12:17 AM	TYLER, TX	903-561-0748	480-575-1845	3	DDC	DAY	2.97
37	11	05/21/04	10:33 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
38	12	05/21/04	12:01 PM	TYLER, TX	903-581-5930	480-575-1607	6	DDC	DAY	5.94
39	13	05/21/04	2:33 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
40	13	05/25/04	2:09 PM	TYLER, TX	903-581-5930	480-575-7303	9	DDC	DAY	8.91
41	19	05/27/04	2:44 PM	HALLSVILLE, TX	903-668-4133	480-575-1607	2	DDC	DAY	1.98
42	3	05/27/04	9:10 AM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	1.98
43	21	05/28/04	10:59 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
44	4	05/28/04	10:22 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
45	25	06/07/04	9:57 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
46	12	06/08/04	9:20 AM	TYLER, TX	903-581-5930	480-575-7303	5	DDC	DAY	4.95
47	13	06/11/04	11:51 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
48	42	06/14/04	8:42 AM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	1.98
49	43	06/14/04	12:17 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
50	14	06/14/04	4:03 PM	VAN, TX	903-963-5897	480-575-7303	3	DDC	DAY	2.97

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJUSTMENT #4 - REMOVE LONG-DISTANCE CHARGES

LINE NO.	CALL NUMBER	CALL DATE	CALL TIME	LOCATION CALLED	PHONE NUMBER CALLED	PHONE NUMBER BILLED TO	NUMBER OF MINUTES	CALL TYPE	RATE PERIOD	AMOUNT BILLED
1	14	06/15/04	9:56 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	$ 1.98
2	18	06/18/04	2:05 PM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
3	18	06/18/04	1:16 PM	TYLER, TX	903-581-5930	480-575-7303	5	DDC	DAY	4.95
4	20	06/21/04	2:02 PM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
5	2	06/24/04	1:59 PM	TYLER, TX	903-581-5930	480-575-1607	7	DDC	DAY	6.93
6	6	06/24/04	11:14 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
7	7	06/24/04	11:31 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
8	10	07/06/04	10:55 AM	PALASTINE, TX	903-724-1583	480-575-1607	2	DDC	DAY	1.98
9	11	07/06/04	11:18 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
10	13	07/06/04	1:44 PM	TYLER, TX	903-593-2882	480-575-1607	3	DDC	DAY	2.97
11	15	07/06/04	2:58 PM	LONGVIEW, TX	903-445-0799	480-575-1607	3	DDC	DAY	2.97
12	17	07/06/04	4:07 PM	TYLER, TX	903-714-1090	480-575-1607	6	DDC	DAY	5.94
13	18	07/06/04	4:12 PM	TYLER, TX	903-714-1095	480-575-1607	2	DDC	DAY	1.98
14	19	07/06/04	12:00 AM	TYLER, TX	903-561-9527	480-575-1607	1	DDC	DAY	0.99
15	20	07/06/04	4:19 PM	TYLER, TX	903-561-9527	480-575-1607	2	DDC	DAY	1.98
16	22	07/07/04	9:39 AM	TYLER, TX	903-939-0646	480-575-1607	1	DDC	DAY	0.99
17	23	07/07/04	9:41 AM	HAWKINS, TX	903-769-5838	480-575-1607	8	DDC	DAY	7.92
18	25	07/07/04	10:14 AM	TYLER, TX	903-581-8077	480-575-1607	1	DDC	DAY	0.99
19	26	07/07/04	10:36 AM	TYLER, TX	903-534-8063	480-575-1607	1	DDC	DAY	0.99
20	27	07/07/04	10:40 AM	GRAND PRARI, TX	214-802-5353	480-575-1607	6	DDC	DAY	5.94
21	28	07/07/04	10:47 AM	BULLARD, TX	903-894-7822	480-575-1607	3	DDC	DAY	2.97
22	29	07/07/04	11:06 AM	TYLER, TX	903-534-8063	480-575-1607	1	DDC	DAY	0.99
23	30	07/07/04	2:35 PM	TYLER, TX	903-526-1700	480-575-1607	1	DDC	DAY	0.99
24	31	07/07/04	2:55 PM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
25	22	07/07/04	9:40 AM	TYLER, TX	903-595-2283	480-575-7303	2	DDC	DAY	1.98
26	23	07/07/04	10:37 AM	TYLER, TX	903-581-8077	480-575-7303	1	DDC	DAY	0.99
27	24	07/07/04	11:08 AM	TYLER, TX	903-581-8077	480-575-7303	1	DDC	DAY	0.99
28	1	07/08/04	3:39 PM	TYLER, TX	903-593-2882	480-575-1607	2	DDC	DAY	1.98
29	12	07/08/04	8:04 AM	BULLARD, TX	903-894-7151	480-575-1607	2	DDC	DAY	1.98
30	13	07/08/04	8:25 AM	TYLER, TX	903-530-2657	480-575-1607	1	DDC	DAY	0.99
31	16	07/08/04	12:00 PM	TYLER, TX	903-570-0092	480-575-1607	5	DDC	DAY	4.95
32	18	07/08/04	1:24 PM	TYLER, TX	903-534-8063	480-575-1607	1	DDC	DAY	0.99
33	19	07/08/04	2:31 PM	TYLER, TX	903-520-2657	480-575-1607	1	DDC	DAY	0.99
34	20	07/08/04	2:32 PM	TYLER, TX	903-530-2657	480-575-1607	4	DDC	DAY	3.96
35	21	07/08/04	2:39 PM	TYLER, TX	903-561-9527	480-575-1607	2	DDC	DAY	1.98
36	23	07/08/04	2:48 PM	TYLER, TX	903-258-9537	480-575-1607	6	DDC	DAY	5.94
37	24	07/08/04	2:55 PM	BULLARD, TX	903-894-9273	480-575-1607	1	DDC	DAY	0.99
38	2	07/09/04	3:47 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
39	5	07/09/04	12:24 PM	BULLARD, TX	903-894-3569	480-575-1607	37	DDC	DAY	36.63
40	8	07/09/04	1:35 PM	TYLER, TX	903-570-5344	480-575-1607	2	DDC	DAY	1.98
41	12	07/09/04	3:14 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
42	29	07/09/04	1:36 PM	BULLARD, TX	903-894-7944	480-575-7303	1	DDC	DAY	0.99
43	13	07/12/04	2:01 PM	TYLER, TX	903-581-5930	480-575-1607	4	DDC	DAY	3.96
44	15	07/13/04	10:48 AM	TYLER, TX	903-534-1320	480-575-1607	6	DDC	DAY	5.94
45	17	07/13/04	11:05 AM	BULLARD, TX	903-894-7122	480-575-1607	11	DDC	DAY	10.89
46	18	07/13/04	11:23 AM	BULLARD, TX	903-894-7122	480-575-1607	1	DDC	DAY	0.99
47	24	07/13/04	12:43 PM	TYLER, TX	903-581-8545	480-575-1607	2	DDC	DAY	1.98
48	31	07/13/04	10:29 AM	LKPALSTINE, TX	903-825-0103	480-575-7303	1	DDC	DAY	0.99
49	25	07/14/04	10:47 PM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	2.97
50	26	07/14/04	12:41 PM	LINDL SWAN, TX	903-881-2300	480-575-1607	1	DDC	DAY	0.99

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJUSTMENT #4 - REMOVE LONG-DISTANCE CHARGES

LINE NO.	CALL NUMBER	CALL DATE	CALL TIME	LOCATION CALLED	PHONE NUMBER CALLED	PHONE NUMBER BILLED TO	NUMBER OF MINUTES	CALL TYPE	RATE PERIOD	AMOUNT BILLED
1	27	07/14/04	12:45 PM	DALLAS, TX	214-792-4223	480-575-1607	5	DDC	DAY	$ 4.95
2	8	07/15/04	8:18 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
3	32	07/19/04	10:39 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
4	37	07/20/04	11:04 AM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
5	41	07/21/04	1:56 PM	HALLSVILLE, TX	903-668-4133	480-575-1607	4	DDC	DAY	3.96
6	16	07/22/04	3:30 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
7	43	07/26/04	10:31 AM	HALLSVILLE, TX	903-668-4133	480-575-1607	3	DDC	DAY	2.97
8	35	07/26/04	10:28 AM	TYLER, TX	903-581-5930	480-575-7303	2	DDC	DAY	1.98
9	36	07/26/04	12:57 PM	HALLSVILLE, TX	903-668-4133	480-575-7303	1	DDC	DAY	0.99
10	44	07/27/04	3:47 PM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
11	48	07/28/04	1:56 PM	TYLER, TX	903-581-5930	480-575-1607	4	DDC	DAY	3.96
12	49	07/29/04	8:34 AM	BULLARD, TX	903-894-5100	480-575-1607	2	DDC	DAY	1.98
13	50	07/29/04	10:51 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
14	52	07/30/04	12:00 AM	TYLER, TX	903-530-0040	480-575-1607	1	DDC	DAY	0.99
15	53	07/30/04	9:35 AM	WHITEHOUSE, TX	903-839-3939	480-575-1607	1	DDC	DAY	0.99
16	1	08/02/04	8:48 AM	TYLER, TX	903-530-0040	480-575-1607	1	DDC	DAY	0.99
17	2	08/02/04	9:35 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	1.98
18	3	08/03/04	9:32 AM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.99
19	26	08/04/04	4:17 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.99
20	4	08/05/04	11:03 AM	TYLER, TX	903-530-0040	480-575-1607	1	DDC	DAY	0.99
21	4	08/20/04	4:04 PM	TYLER, TX	903-591-1002	480-575-1607	1	DDC	DAY	0.07
22	5	08/23/04	9:16 AM	BULLARD, TX	903-894-4130	480-575-1607	4	DDC	DAY	0.28
23	6	08/24/04	3:03 PM	ATHENS, TX	903-477-7255	480-575-1607	1	DDC	DAY	0.07
24	10	08/30/04	9:37 AM	TYLER, TX	903-581-3414	480-575-1607	1	DDC	DAY	0.07
25	11	08/30/04	9:39 AM	TYLER, TX	903-561-1070	480-575-1607	3	DDC	DAY	0.21
26	12	08/30/04	9:42 AM	TYLER, TX	903-216-7144	480-575-1607	1	DDC	DAY	0.07
27	13	09/02/04	1:00 PM	TYLER, TX	903-521-3800	480-575-1607	9	DDC	DAY	0.62
28	14	09/02/04	1:44 PM	BARKER, TX	281-579-2028	480-575-1607	1	DDC	DAY	0.07
29	15	09/02/04	3:27 PM	BARKER, TX	281-579-2028	480-575-1607	3	DDC	DAY	0.21
30	16	09/03/04	9:09 PM	TYLER, TX	903-534-0946	480-575-1607	3	DDC	DAY	0.21
31	17	09/03/04	9:13 AM	TYLER, TX	903-581-9990	480-575-1607	1	DDC	DAY	0.07
32	18	09/03/04	1:23 PM	TYLER, TX	903-581-5930	480-575-1607	5	DDC	DAY	0.35
33	7	09/03/04	1:22 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
34	8	09/03/04	1:33 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
35	7	09/03/04	9:15 AM	TYLER, TX	903-581-6441	480-575-7303	4	DDC	DAY	0.28
36	19	09/09/04	11:11 AM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.07
37	21	09/09/04	11:23 AM	TYLER, TX	903-595-2283	480-575-1607	3	DDC	DAY	0.21
38	22	09/13/04	10:07 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	0.14
39	24	09/15/04	2:20 PM	TYLER, TX	903-581-5930	480-575-1607	6	DDC	DAY	0.41
40	25	09/16/04	9:23 AM	HALLSVILLE, TX	903-668-4133	480-575-1607	2	DDC	DAY	0.14
41	26	09/17/04	8:48 AM	BARKER, TX	281-579-2028	480-575-1607	1	DDC	DAY	0.07
42	27	09/21/04	9:54 AM	TYLER, TX	903-581-5930	480-575-1607	6	DDC	DAY	0.41
43	29	09/28/04	11:12 AM	TYLER, TX	903-581-5930	480-575-7303	1	DDC	DAY	0.07
44	31	09/29/04	12:33 PM	DENISON, TX	903-465-4506	480-575-7303	1	DDC	DAY	0.07
45	32	09/29/04	12:50 PM	TYLER, TX	903-581-5930	480-575-7303	1	DDC	DAY	0.07
46	6	09/30/04	9:24 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	0.21
47	7	09/30/04	10:02 AM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.07
48	8	09/30/04	10:35 AM	LINDL SWAN, TX	903-881-2300	480-575-1607	8	DDC	DAY	0.55
49	9	09/30/04	2:15 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.07
50	29	09/30/04	12:49 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJUSTMENT #4 - REMOVE LONG-DISTANCE CHARGES

LINE NO.	CALL NUMBER	CALL DATE	CALL TIME	LOCATION CALLED	PHONE NUMBER CALLED	PHONE NUMBER BILLED TO	NUMBER OF MINUTES	CALL TYPE	RATE PERIOD	AMOUNT BILLED
1	30	09/30/04	2:08 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	$ 0.07
2	31	09/30/04	2:55 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
3	32	09/30/04	3:16 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
4	33	09/30/04	4:56 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
5	10	10/01/04	1:51 PM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	0.14
6	11	10/01/04	2:05 PM	TYLER, TX	903-581-5930	480-575-1607	1	DDC	DAY	0.07
7	34	10/01/04	11:04 AM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
8	35	10/01/04	1:59 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
9	36	10/01/04	2:57 PM	TYLER, TX	903-509-4713	480-575-1845	1	DDC	DAY	0.07
10	37	10/01/04	3:45 PM	TYLER, TX	903-509-4713	480-575-1845	2	DDC	DAY	0.14
11	12	10/04/04	1;26 PM	TYLER, TX	903-581-5930	480-575-1607	8	DDC	DAY	0.55
12	13	10/06/04	2:21 PM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	0.14
13	14	10/11/04	9:33 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	0.14
14	15	10/11/04	12:00 AM	TEXARKANA, TX	903-277-2980	480-575-1607	1	DDC	DAY	0.07
15	16	10/11/04	9:53 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	0.14
16	20	10/19/04	9:28 AM	TYLER, TX	903-581-5930	480-575-1607	3	DDC	DAY	0.21
17	3	10/28/04	11:03 AM	TYLER, TX	903-581-4630	480-575-1607	1	DDC	DAY	0.07
18	5	11/02/04	11:29 AM	TYLER, TX	903-581-5930	480-575-1607	2	DDC	DAY	0.14
19	7	11/03/04	10:06 AM	BARKER, TX	281-579-2028	480-575-1607	1	DDC	DAY	0.07
20	8	11/03/04	11:26 AM	TYLER, TX	903-581-5930	480-575-1607	6	DDC	DAY	0.41
21	13	11/08/04	1:56 PM	WHITEHOUSE, TX	903-839-8829	480-575-1607	1	DDC	DAY	0.07
22	14	11/08/04	2:00 PM	GRANDPRARI, TX	214-883-3200	480-575-1607	4	DDC	DAY	0.28
23	20	11/09/04	11:19 AM	TYLER, TX	903-581-5930	480-575-1607	5	DDC	DAY	0.35
24	23	11/10/04	8:46 AM	BULLARD ,TX	903-894-8976	480-575-1607	6	DDC	DAY	0.41
25	24	11/12/04	9:57 AM	TYLER, TX	903-360-6915	480-575-1607	1	DDC	DAY	0.07
26	27	11/16/04	2:55 PM	TYLER, TX	903-561-9527	480-575-1607	2	DDC	DAY	0.14
27	28	11/16/04	2:59 PM	TYLER, TX	903-581-5930	480-575-1607	4	DDC	DAY	0.28
28	5	12/09/04	3:42 PM	TYLER, TX	903-509-4713	480-575-7303	2	D	DAY	2.16
29	6	12/09/04	3:58 PM	TYLER, TX	903-509-4713	480-575-7303	2	D	DAY	2.16
30	16	12/18/04	9:58 AM	TYLER, TX	903-566-2887	480-575-7303	4	D	DAY	4.32
31	23	12/23/04	2:55 PM	TYLER, TX	903-509-4713	480-575-7303	4	D	DAY	4.32
32	24	12/29/04	4:11 PM	TYLER, TX	903-509-4713	480-575-7303	2	D	DAY	2.16
33	25	12/29/04	4:13 PM	TYLER, TX	903-509-4713	480-575-7303	2	D	DAY	2.16
34										
35	LONG-DISTANCE CHARGES PER COMPANY									$ 520.14
36										
37	LONG-DISTANCE CHARGES PER RUCO									$ -
38										
39	RUCO ADJUSTMENT (LINE 37 - LINE 35)									$ (520.14)

REFERENCES:
ACC STAFF DATA REQUEST CSB 1.40
ACC STAFF DATA REQUEST CSB 2.15

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJ. #5 - DEPRECIATION AND AMORTIZATION EXPENSE

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-6

LINE NO.	ACCT. NO.	PLANT ACCOUNT NAME	(A) TEST YEAR BALANCE PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED BALANCE	(D) COMPONENT DEPRECIATION RATES	(E) RUCO RECOMMENDED DEPRECIATION EXPENSE
1	351	ORGANIZATION*	$0	$0	$0	0.00%	$ -
2	352	FRANCHISES*	-	3,228	3,228	0.00%	-
3	353	LAND AND LAND RIGHTS*	461,446	-	461,446	0.00%	-
4	354	STRUCTURES AND IMPROVEMENTS	1,245,292	-	1,245,292	3.33%	41,468
5	355	POWER GENERATION EQUIPMENT	-	-	-	5.00%	-
6	360	COLLECTION SEWERS - FORCE	253,491	(24,706)	228,785	2.00%	4,576
7	361	COLLECTION SEWERS - GRAVITY	3,608,619	-	3,608,619	2.00%	72,172
8	362	SPECIAL COLLECTING STRUCTURES	-	-	-	2.00%	-
9	363	SERVICES TO CUSTOMERS	158,802	-	158,802	2.00%	3,176
10	364	FLOW MEASURING DEVICES	39,878	-	39,878	10.00%	3,988
11	365	FLOW MEASURING INSTALLATIONS	158,358	-	158,358	10.00%	15,836
12	370	RECEIVING WELLS	696,506	-	696,506	3.33%	23,194
13	371	EFFLUENT PUMPING EQUIPMENT	451,705	-	451,705	12.50%	56,463
14	380	TREATMENT AND DISPOSAL EQUIPMENT	-	-	-	5.00%	-
15	381	PLANT SEWERS	121,651	-	121,651	5.00%	6,083
16	382	OUTFALL SEWER LINES	-	-	-	3.33%	-
17	389	OTHER PLANT AND MISC. EQUIPMENT	808,394	19,574	827,968	6.67%	55,225
18	390	OFFICE FURNITURE AND EQUIPMENT	365,512	-	365,512	6.67%	24,380
19	391	TRANSPORTATION EQUIPMENT	87,811	-	87,811	20.00%	17,562
20	393	TOOLS, SHOP AND GARAGE EQUIPMENT	-	-	-	5.00%	-
21	394	LABORATORY EQUIPMENT	7,279	-	7,279	10.00%	728
22	395	POWER OPERATED EQUIPMENT	-	-	-	5.00%	-
23	398	OTHER TANGIBLE PLANT	-	-	-	10.00%	-
24							
25		TEST YEAR TOTALS	$ 8,464,745	$ (1,904)	$ 8,462,841		$ 324,850
26							
27		SCOTTSDALE TREATMENT CAPACITY	0	1,913,706	1,913,706	5.00%	95,685
28							
29		TOTAL	$ 8,464,745	$ 1,911,802	$10,376,547		$ 420,536
30							
31		LESS:					
32							
33		AMORTIZATION OF CONTRIBUTIONS IN AID OF CONSTRUCTION** @ 4.0322% COMPOSITE RATE **					$ 233,881
34							
35		TOTAL PRO FORMA DEPRECIATION & AMORTIZATION EXPENSE PER RUCO					$ 186,655
36							
37		DEPRECIATION & AMORTIZATION EXPENSE PER COMPANY					$ 126,749
38							
39		DEPRECIATION & AMORTIZATION EXPENSE ADJUSTMENT (LINE 31 - LINE 33)					$ 59,906

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-2, PAGE 3K (INCUDING POST-TY ADJUSTMENTS ON SCHEDULE B-2, PAGE 2)
COLUMN (B): COLUMN (C) - COLUMN (A)
COLUMN (C): RUCO SCHEDULE MDC-2
COLUMN (D): COMPANY SCHEDULE C-2, PAGE 2
COLUMN (E): COLUMN (C) x COLUMN (D)

NOTE:
* NON-DEPRECIABLE PLANT ASSETS
** TEST YEAR ADJUSTED CIAC x COMPOSITE RATE OF DEPRECIATION = $5,800,321 x 4.0322% = $233,881

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJ. #6 - PROPERTY TAX EXPENSE

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-7

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	REVENUES - 2002	$ 1,136,926	COMPANY SCH. E-2, PAGE 1
2	REVENUES - 2003	1,144,038	COMPANY SCH. E-2, PAGE 1
3	REVENUES - 2004	1,190,412	COMPANY SCH. E-2, PAGE 1
4	TOTAL	$ 3,471,376	SUM LINES 1, 2, & 3
5	3 YEAR AVERAGE	$ 1,157,125	LINE 4/3 YEARS
6	MULTIPLIER FOR REVENUES (2 X LAST 3 YRS. AVERAGE REVENUE)	x 2	ADOR VALUATION FACTOR
7	REVENUES FOR FULL CASH VALUE	$ 2,314,251	LINE 5 X 2 (MULTIPLIER FOR REVENUES)
8	ADD: 10% OF CWIP BALANCE	10,380	COMPANY SCH. E-1, PAGE 1 X 10.00%
9	LESS: LICENSED VEHICLES	80,169	COMPANY SCH. B-2, PAGE 3K LESS ACCUM. DEPR.
10	FULL CASH VALUE	$ 2,244,462	
11	ASSESSMENT RATIO	25%	PER ADOR VALUATION METHOD
12	ASSESSED VALUE	$ 561,116	LINE 10 X LINE 11
13	PROPERTY TAX RATE	6.3107%	PER TAX BILLS (RUCO DATA REQUEST 1.05)
14	PROPERTY TAXES PAYABLE PER RUCO	$ 35,410	LINE 12 X LINE 13
15	PROPERTY TAXES PER COMPANY	45,745	COMPANY SCH. C-1
16	ADJUSTMENT	$ (10,335)	LINE 14 MINUS LINE 15

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
OPERATING ADJ. #7 - INCOME TAXES

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-8

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
	FEDERAL INCOME TAXES:		
1	OPERATING INCOME BEFORE INCOME TAXES	$ 150,987	SCH. WAR-3
	LESS:		
2	ARIZONA STATE TAX	6,564	LINE 11
3	INTEREST EXPENSE	56,780	NOTE (a)
4	FEDERAL TAXABLE INCOME	$ 87,642	LINE 1 - LINES 2 & 3
5	FEDERAL INCOME TAX RATE	21.33%	TAX RATE
6	FEDERAL INCOME TAX EXPENSE	$ 18,693	LINE 4 X LINE 5
7	FEDERAL INCOME TAXES PER COMPANY FILING	(6,544)	COMPANY SCH. C-1
8	RUCO FEDERAL INCOME TAX ADJUSTMENT	$ 25,237	LINE 6 - LINE 7
	STATE INCOME TAXES:		
9	OPERATING INCOME BEFORE INCOME TAXES	$ 150,987	LINE 1
	LESS:		
10	INTEREST EXPENSE	56,780	NOTE (A)
11	STATE TAXABLE INCOME	$ 94,207	LINE 7 - LINE 8
12	STATE TAX RATE	6.968%	TAX RATE
13	STATE INCOME TAX EXPENSE	$ 6,564	LINE 9 X LINE 10
14	STATE INCOME TAXES PER COMPANY FILING	-	COMPANY SCH. C-1
15	RUCO STATE INCOME TAX ADJUSTMENT	$ 6,564	LINE 13 - LINE 14
16	TOTAL STATE & FEDERAL INCOME TAXES	$ 31,801	LINE 8 + LINE 15

NOTE (a):
INTEREST SYCHRONIZATION

ADJUSTED RATE BASE	$ 1,372,834
WEIGHTED COST OF DEBT	4.14%
	$ 56,780

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
COST OF CAPITAL

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR - 9

WEIGHTED COST OF CAPITAL ASSUMING THE COMMISSION REJECTS THE COMPANY-PROPOSED OPERATING LEASE

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	LONG-TERM DEBT	$ -	$ 1,201,726	$ 1,201,726	44.00%	9.40%	4.14%
2	COMMON EQUITY	1,498,949	-	1,498,949	56.00%	9.49%	5.32%
3	TOTAL CAPITALIZATION	$ 1,498,949	$ 1,201,726	$ 2,700,675	100.00%		
4	**WEIGHTED COST OF CAPITAL**						9.45%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): COST OF CAPITAL DIRECT TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): COST OF CAPITAL DIRECT TESTIMONY, WAR
COLUMN (F): COLUMN (D) x COLUMN (E)

WEIGHTED COST OF CAPITAL ASSUMING THE COMMISSION ADOPTS THE COMPANY-PROPOSED OPERATING LEASE

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) RUCO WEIGHTED COST
1	LONG-TERM DEBT	43.00%	8.16%	3.51%
2	COMMON EQUITY	57.00%	9.49%	5.41%
3	TOTAL CAPITALIZATION	100.00%		
4	**WEIGHTED COST OF CAPITAL**			8.92%

REFERENCES:
COLUMN (A): COST OF CAPITAL DIRECT TESTIMONY, WAR
COLUMN (B): COST OF CAPITAL SCHEDULE WAR-1, PAGE 2 & COST OF CAPITAL DIRECT TESTIMONY, WAR
COLUMN (C): COLUMN (A) x COLUMN (B)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
PROPOSED RATES

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-10

LINE NO.	CUSTOMER CLASSIFICATION	PRESENT RATES	COMPANY PROPOSED RATES	RUCO RECOMMENDED RATES
1	RESIDENTIAL	$ 38.00	$ 43.19	$ 38.04
2				
3	COMMERCIAL (STANDARD RATE PER GALLON)	$ 0.152360	$ 0.173160	$ 0.152539
4				
5	COMMERCIAL (SPECIAL RATE PER GALLON):			
6				
7	B-H ENTERPRISES (WEST)	$ 0.116850	$ 0.132800	$ 0.116987
8	B-H ENTERPRISES (EAST)	$ 0.116850	$ 0.132800	$ 0.116987
9	BARB'S PET GROOMING	$ 0.116850	$ 0.132800	$ 0.116987
10	BOULDERS RESORT	$ 0.118427	$ 0.134590	$ 0.118566
11	CAREFREE DENTAL	$ 0.116850	$ 0.132800	$ 0.116987
12	RIDGECREST REALTY	$ 0.118180	$ 0.134310	$ 0.118319
13	DESERT FOREST	$ 0.136090	$ 0.154670	$ 0.136250
14	DESERT HILLS PHARMACY	$ 0.142060	$ 0.161450	$ 0.142227
15	EL PEDREGAL	$ 0.116850	$ 0.132800	$ 0.116987
16	LEMON TREE	$ 0.144000	$ 0.163760	$ 0.144169
17	BODY SHOP	$ 0.145440	$ 0.165290	$ 0.145611
18	SPANISH VILLAGE	$ 0.116850	$ 0.132800	$ 0.116987
19	BOULDERS CLUB	$ 0.116850	$ 0.132800	$ 0.116987
20	ANTHONY VUITAGGIO	$ 0.129870	$ 0.147600	$ 0.130023
21				
22	EFFLUENT CUSTOMERS	$ 0.374400	$ 0.425510	$ 0.374840

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
MONTHLY MINIMUM CHARGES BASED ON AVERAGE CONSUMPTION

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-11

LINE NO.	CUSTOMER CLASSIFICATION		(A) GALLONS		(B) PRESENT MONTHLY CHARGE	(C) COMPANY PROPOSED MONTHLY CHARGE	(D) COMPANY PROPOSED DOLLAR INCREASE	(E) COMPANY PROPOSED PERCENT. INCREASE	(F) RUCO RECOMMENDED MONTHLY CHARGE	(G) RUCO RECOMMENDED DOLLAR INCREASE	(H) RUCO PERCENT. INCREASE
1	RESIDENTIAL		-		$ 38.00	$ 43.19	$ 5.19	13.658%	$ 38.04	$ 0.04	0.12%
2											
3	COMMERCIAL (STANDARD RATE PER GALLON)		570	(a)	$ 86.85	$ 98.70	$ 11.86	13.652%	$ 86.95	$ 0.10	0.12%
4											
5	COMMERCIAL (SPECIAL RATE PER GALLON):										
6											
7	B-H ENTERPRISES (WEST)	(b)	2,525		$ 295.05	$ 335.32	$ 40.27	13.650%	$ 295.39	$ 0.35	0.12%
8	B-H ENTERPRISES (EAST)		1,400		163.59	185.92	22.33	13.650%	163.78	0.19	0.12%
9	BARB'S PET GROOMING	(b)	250		29.21	33.20	3.99	13.650%	29.25	0.03	0.12%
10	BOULDERS RESORT		29,345		3,475.23	3,949.60	474.37	13.650%	3,479.32	4.09	0.12%
11	CAREFREE DENTAL	(b)	1,625		189.98	215.91	25.93	13.648%	190.21	0.23	0.12%
12	RIDGECREST REALTY		450		53.18	60.44	7.26	13.649%	53.24	0.06	0.12%
13	DESERT FOREST		7,000		952.63	1,082.66	130.03	13.650%	953.75	1.12	0.12%
14	DESERT HILLS PHARMACY		800		113.65	129.16	15.51	13.649%	113.78	0.13	0.12%
15	EL PEDREGAL		15,787		1,844.69	2,096.49	251.80	13.650%	1,846.88	2.19	0.12%
16	LEMON TREE		300		43.20	49.10	5.90	13.653%	43.25	0.05	0.12%
17	BODY SHOP		1,000		145.44	165.29	19.85	13.648%	145.61	0.17	0.12%
18	SPANISH VILLAGE	(b)	4,985		582.50	662.01	79.51	13.650%	583.18	0.68	0.12%
19	BOULDERS CLUB		1,200		140.22	159.36	19.14	13.650%	140.38	0.16	0.12%
20	ANTHONY VUITAGGIO		300		38.96	44.28	5.32	13.652%	39.01	0.05	0.12%
21											
22	EFFLUENT CUSTOMERS		3,226,904	(c)	$ 1,208.15	$ 1,373.08	$ 164.93	13.651%	$ 1,209.57	1.42	0.12%

REFERENCES
COLUMN (A) THRU COLUMN (C): COMPANY SCHEDULE H
COLUMN (D): COLUMN (C) - COLUMN (B)
COLUMN (E): COLUMN (D) ÷ COLUMN (A)
COLUMN (F): TESTIMONY WAR
COLUMN (G): COLUMN (F) - COLUMN (B)
COLUMN (H): COLUMN (G) ÷ COLUMN (A)

NOTES:
(a) BASED ON AVERAGE TEST YEAR CONSUMPTION OF 570 GALLONS
(b) NO LONGER ON THE SYSTEM
(c) AVERAGE TEST YEAR CONSUMPTION OF 3,226,904 GALLONS

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
BILLING ANALYSIS - COMMERCIAL CUSTOMER (STANDARD RATE)

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-12

LINE NO.	CONSUMPTION IN GALLONS	(A) PRESENT RATES	(B) COMPANY PROPOSED RATES	(C) INCREASE ($)	(D) INCREASE (%)	(E) RUCO RECOMMENDED RATES	(F) INCREASE ($)	(G) INCREASE (%)
1	0	$ -	$ -	$ -	0.00%	$ -	$ -	0.000%
2	100	15.24	17.32	2.08	13.65%	15.25	0.02	0.118%
3	200	30.47	34.63	4.16	13.65%	30.51	0.04	0.118%
4	300	45.71	51.95	6.24	13.65%	45.76	0.05	0.118%
5	400	60.94	69.26	8.32	13.65%	61.02	0.07	0.118%
6	500	76.18	86.58	10.40	13.65%	76.27	0.09	0.118%
7	600	91.42	103.90	12.48	13.65%	91.52	0.11	0.118%
8	700	106.65	121.21	14.56	13.65%	106.78	0.13	0.118%
9	800	121.89	138.53	16.64	13.65%	122.03	0.14	0.117%
10	900	137.12	155.84	18.72	13.65%	137.29	0.16	0.118%
11	1,000	152.36	173.16	20.80	13.65%	152.54	0.18	0.117%
12	1,500	228.54	259.74	31.20	13.65%	228.81	0.27	0.118%
13	2,000	304.72	346.32	41.60	13.65%	305.08	0.36	0.118%
14	2,500	380.90	432.90	52.00	13.65%	381.35	0.45	0.118%
15	3,000	457.08	519.48	62.40	13.65%	457.62	0.54	0.118%
16	3,500	533.26	606.06	72.80	13.65%	533.89	0.63	0.118%
17	4,000	609.44	692.64	83.20	13.65%	610.16	0.72	0.118%
18	4,500	685.62	779.22	93.60	13.65%	686.43	0.81	0.117%
19	5,000	761.80	865.80	104.00	13.65%	762.70	0.90	0.118%
20	6,000	914.16	1,038.96	124.80	13.65%	915.23	1.07	0.118%
21	7,000	1,066.52	1,212.12	145.60	13.65%	1,067.77	1.25	0.118%
22	8,000	1,218.88	1,385.28	166.40	13.65%	1,220.31	1.43	0.118%
23	9,000	1,371.24	1,558.44	187.20	13.65%	1,372.85	1.61	0.117%
24	10,000	1,523.60	1,731.60	208.00	13.65%	1,525.39	1.79	0.118%
25	50,000	7,618.00	8,658.00	1,040.00	13.65%	7,626.95	8.95	0.117%
26	100,000	15,236.00	17,316.00	2,080.00	13.65%	15,253.90	17.90	0.117%
27	250,000	38,090.00	43,290.00	5,200.00	13.65%	38,134.76	44.76	0.117%
28	500,000	76,180.00	86,580.00	10,400.00	13.65%	76,269.51	89.51	0.117%
29								
30								
31	AVG. NO. OF CUST:	121	121			121		
32								
33	AVG. USE (GAL.):	570	570			570		
34	MONTHLY BILL:	$86.85	$98.70	$ 11.86	13.65%	$86.95	$ 0.10	0.118%
35								
36	MEDIAN USE (GAL.) :	105	105			105		
37	MONTHLY BILL:	$16.00	$18.18	$ 2.18	13.65%	$16.02	$ 0.02	0.117%

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
REVENUE SUMMARY BY CUSTOMER CLASS

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR-13

LINE NO.	DESCRIPTION	(C) PRESENT RATES	(C) COMPANY PROPOSED RATES	(C) RUCO RECOMMENDED RATES
1	RESIDENTIAL	$ 768,816	$ 893,516	$ 787,068
2				
3	COMMERCIAL (STANDARD RATE PER GALLON)	311,041	353,504	311,407
4				
5	COMMERCIAL (SPECIAL RATE PER GALLON):			
6				
7	B-H ENTERPRISES (WEST)	-	-	-
8	B-H ENTERPRISES (EAST)	1,963	2,231	1,965
9	BARB'S PET GROOMING	-	-	-
10	BOULDERS RESORT	41,704	47,394	41,753
11	CAREFREE DENTAL	-	-	-
12	RIDGECREST REALTY	638	725	639
13	DESERT FOREST	11,432	12,992	11,445
14	DESERT HILLS PHARMACY	1,364	1,550	1,365
15	EL PEDREGAL	22,137	25,158	22,163
16	LEMON TREE	518	589	519
17	BODY SHOP	1,745	1,983	1,747
18	SPANISH VILLAGE	-	-	-
19	BOULDERS CLUB	1,683	1,912	1,685
20	ANTHONY VUITAGGIO	468	531	468
21		-		
22	EFFLUENT CUSTOMERS	14,498	16,477	14,515
	TOTAL REVENUE FROM FLAT RATE CHARGES	$ 1,178,006	$ 1,358,565	$ 1,196,738

BLACK MOUNTAIN SEWER CORPORATION

DOCKET NO. SW-02361A-05-0657

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

COST OF CAPITAL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

March 9, 2006

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and your qualifications in the field of utilities regulation.

A. Appendix I, which is attached to this testimony, describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Black Mountain Sewer Corporation's ("BMSC" or "Company") application for a permanent rate increase ("Application").

Q. Briefly describe BMSC.

A. BMSC is a wholly owned subsidiary of Algonquin Water Resources of America, which is a wholly owned subsidiary of the Algonquin Power Income Fund ("Algonquin Fund" or "Parent"), a mutual fund, or trust, which is listed on the Toronto Stock Exchange (ticker symbol APF.UN). Prior to being acquired by the Algonquin Fund, the Company was owned by

Boulders Joint Venture and operated under the name of Boulders Carefree Sewer. In addition to BMSC, the Algonquin Fund also owns and operates four other ACC regulated utilities: Bella Vista Water Company, in Sierra Vista; Gold Canyon Sewer, located east of Apache Junction; Litchfield Park Services Company, situated on the west side of the Phoenix metropolitan area; and Rio Rico Utilities, Inc., located just north of Nogales on the border between Arizona and Mexico. The Algonquin Fund also owns Algonquin Water Services, which directly oversees the daily operations of the aforementioned Arizona public service companies.

Q. Briefly explain what a mutual fund is?

A. A mutual fund is a type of investment vehicle that generally provides investors with the opportunity to place their funds into a professionally managed portfolio of financial instruments such as stocks or bonds. In the case of a stock mutual fund, the fund's manager will buy and sell on the basis of how well a stock meets the fund's investment criteria, such as providing a specific level of dividend income and/or achieving projected levels of capital appreciation. Unlike the price of a stock or bond, the value of a mutual fund is expressed as its net asset value ("NAV"). Fund managers generally realize a profit from management fees, which are normally collected as a fixed percentage, typically between 0.5 percent and 2.00 percent a year, of the fund's NAV. Management fees are normally deducted from shareholder's assets on an annual basis. Closedended funds have a fixed number of shares that are bought and sold on securities exchanges in the same manner as individual stocks and bonds. Open-ended funds, on the other hand, offer new shares and redeem existing shares on a continual basis.

Q. How is the Algonquin Fund structured?

A. The Algonquin Fund is an open-ended fund with an investment portfolio comprised of utilities involved in the production of electricity and the provision of water and wastewater services[1]. These individual utilities make up the Algonquin Fund's Hydroelectric, Cogeneration, Alternative Fuels and Infrastructure Divisions. Instead of a collection of stocks or bonds, the fund is comprised of utilities that are bought, held and sold in the hope of achieving desired returns on investment. In this respect, the Algonquin fund is no different than a utility holding company whose shares are publicly traded in the financial markets. Shares of the funds are referred to as units and shareholders are referred to as unitholders. As I explained above, the Algonquin Fund's managers derive their income from management fees. A copy of the Algonquin Fund's annual report for 2004 can be viewed in Attachment A.

[1] According to information provided on the website of the Toronto Stock Exchange, the Algonquin Power Income Fund is an open-ended investment trust that owns or has interests in a diverse portfolio of power generating and infrastructure assets across North America, including 48 hydroelectric facilities, five natural gas- fired cogeneration facilities, 18 alternative fuels facilities and 15 water reclamation and distribution facilities. The Algonquin Fund was established in 1997 to provide unitholders with sustainable, highly stable and growing cash flows through a diversified portfolio of energy and infrastructure assets.

Q, Is this form of ownership common for utilities operating in Arizona?

A. No, most investor owned utilities operating in Arizona are either closely held corporate entities, are owned by a utility holding company or, as in the case of many water and wastewater utilities, are owned by a firm that is engaged in land development.

Q. Please explain your role in RUCO's analysis of BMSC's Application.

A. I reviewed BMSC's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and debt (the Company has no preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Were you also responsible for conducting an analysis on the Company's proposed revenue level, rate base and rate design?

A. In addition to performing a cost of capital analysis, I was also responsible for handling the revenue requirement and rate design issues associated with the case. Marylee Diaz Cortez, CPA, RUCO's Manager for Technical Analysis, handled the rate base aspects of BMSC's Application. I have filed my direct testimony on required revenue and rate design under separate cover in this docket.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into three sections. First, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this first section I will also provide a brief overview of the current economic climate that BMSC is operating in. Second, I will compare my recommended capital structure with the Company-proposed capital structure. Third, I will comment on

BMSC's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of BMSC, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.49 percent cost of equity capital. This 9.49 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of approximately 100 percent common equity be rejected by the ACC and that my recommended capital structure, which is comprised of 56 percent common equity and 44 percent long-term debt, be adopted by the Commission.

Cost of Long-Term Debt – I am recommending that the Commission adopt a 9.40 percent cost of long-term debt, which is the cost of BMSC's inter-company loans that I have included in my recommended capital structure.

Cost of Capital – Based on the results of my recommended capital structure, I am recommending a 9.45 percent cost of capital for BMSC, which is the weighted cost of my recommended costs of common equity and long-term debt.

Q. Why do you believe that your recommended 9.45 percent cost of capital is an appropriate rate of return for BMSC to earn on its invested capital?

A. The 9.45 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as BMSC, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for BMSC?

A. Based on the results of my DCF and CAPM analyses, which ranged from 8.89 percent to 10.69 percent for a sample of publicly traded water and gas providers, I am recommending a 9.49 percent cost of equity capital for BMSC. My recommended 9.49 percent figure is the result of DCF analysis, which utilized a sample of publicly traded water providers.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate BMSC's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e.

the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = (D_1 \div P_0) + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth.

This formula is the basis for the standard growth valuation model that I used to determine BMSC's cost of equity capital. It is similar to the model that was used by the Company.

Q. In determining the rate of future dividend growth for BMSC, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[2]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during

[2] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as $g = b \times r$, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[3] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[4] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in

[3] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[4] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[5] Dr. Myron Gordon, the individual responsible for the development of the DCF or constant growth model, identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and v = 1 - [(BV) ÷ (MP)]

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

[5] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation $[(M \div B) + 1] \div 2$.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used $[(M \div B) + 1] \div 2$ as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this specific assumption?

A. Yes. In the recent Southwest Gas Corporation rate case[6], the Commission adopted the recommendations of ACC Staff's cost of cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that

[6] Docket No. G-01551A-04-0876

case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on two separate proxy groups. A water company proxy group comprised of four publicly traded water companies and a natural gas proxy group consisting of eight natural gas local distribution companies ("LDC") which have similar operating characteristics to water providers.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of BMSC?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with BMSC itself. Although shares of Algonquin Fund, the mutual fund that BMSC is included in, are traded on the Toronto Stock Exchange, there is no financial data available on dividends paid on *publicly held* shares of BMSC. Consequently it was necessary to create a proxy by analyzing publicly traded water companies with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your water company proxy for BMSC?

A. Three of the water companies used in the proxy are publicly traded on the New York Stock Exchange ("NYSE"), and one of them, Southwest Water Company, is traded on the National Association of Securities Dealers Automated Quotation System ("NASDAQ"). All four water companies are followed by The Value Line Investment Survey ("Value Line") and are the same companies that comprise Value Line's large capitalization Water Utility Industry segment of the U.S. economy (Attachment B contains Value Line's January 27, 2006 update of the water utility industry and evaluations of the four water companies used in my proxy).

...

Q. In determining your dividend growth rate estimates, both you and the Company's witness analyzed the data on publicly traded water utilities. Why did you and the Company witness analyze only publicly traded water utilities as opposed to firms that provide wastewater service?

A. The use of water utilities was necessitated by the fact that there is a lack of financial and market information available on stand-alone wastewater utilities. This in itself is not a problem, given the fact that both water and wastewater utilities share similar risk characteristics. Both types of utilities provide a basic service for which there are no substitutes and are also subject to strict federal and state regulations.

Q. What companies comprise your water company proxy group?

A. My water company proxy group includes American States Water Company (stock ticker symbol "AWR"), Aqua America, Inc. ("WTR"), formerly known as Philadelphia Suburban Corporation, and California Water Service Group ("CWT"). The fourth water company, Southwest Water Company ("SWWC"), is a relatively new addition to Value Line's water industry segment and debuted in the October 28, 2005 edition of Value Line's Ratings and Reports publication. Each of these water companies face the same types of risk that BMSC faces. For the sake of brevity, I will refer to each of these companies by their appropriate stock ticker symbols henceforth.

Q. Briefly describe the areas served by the companies in your water company sample proxy.

A. In addition to providing water service to residents of Fountain Hills, Arizona, through its wholly owned subsidiary Chaparral City Water Company, AWR serves communities located in Los Angeles, Orange and San Bernardino counties in California. CWT provides service to customers in seventy-five communities in California, New Mexico and Washington. CWT's principal service areas are located in the San Francisco Bay area, the Sacramento, Salinas and San Joaquin Valleys and parts of Los Angeles. SWWC owns and manages regulated systems in California, New Mexico, Oklahoma and Texas. WTR, is a holding company for a large number of water and wastewater utilities operating in nine different states including Pennsylvania, Ohio, New Jersey, Illinois, Maine, North Carolina, Texas, Florida and Kentucky.

Q. Are these the same water companies that BMSC used in its application?

A. With the exception of SWWC, BMSC's cost of capital witness, Mr. Thomas J. Bourassa, used the same water companies that I included in my proxy. In addition to these three companies, Mr. Bourassa also used three other water companies[7] that are included in Value Line's Small and Mid Cap Edition.

[7] Connecticut Water Service, Inc., Middlesex Water Company and SJW Corp.

Q. Why did you exclude the water companies that are followed in Value Line's Small and Mid Cap Edition?

A. Value Line does not provide the same type of forward-looking information (i.e. long-term estimates on return on common equity and share growth) on small and mid-cap companies that it provides on the four water companies that I used in my proxy. Consequently, these water companies are not as suitable as the ones that I have used in my analysis.

Q. What criteria did you use in selecting the eight natural gas LDC's that make up your proxy for BMSC?

A. As are the water companies that I just described, each of the natural gas LDC's used in the proxy are publicly traded on a major stock exchange (all eight trade on the NYSE) and are followed by Value Line. Each of the eight LDC's are tracked in Value Line's natural gas (distribution) industry segment. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment C of my testimony contains Value Line's most recent evaluation of the natural gas proxy group that I used for my cost of common equity analysis.

Q. What companies are included your natural gas sample proxy?

A. The eight natural gas LDC's included in my proxy (and their NYSE ticker symbols) are Cascade Natural Gas Corporation ("CGC"), KeySpan Corp. ("KSE"), Laclede Group, Inc. ("LG"), Northwest Natural Gas Co. ("NWN"), Peoples Energy Corporation ("PGL"), South Jersey Industries, Inc. ("SJI") Southwest Gas Corporation ("SWX"), which is the dominant natural gas provider in Arizona and presently has a rate application before the ACC, and WGL Holdings, Inc. ("WGL").

Q. Briefly describe the regions of the U.S. served by the eight natural gas LDC's that make up your sample proxy.

A. The eight LDC's listed above provide natural gas service to customers in the Northeast (i.e. KSE which serves New York and New England), the Middle Atlantic region (i.e. SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area). The Midwest (i.e. PGL which provides service to Chicago and its suburbs respectively, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. CGC and NWN which serve Washington state and Oregon). Portions of Arizona, Nevada and California are served by SWX.

Q. Did the Company's witness also perform a similar analysis using natural gas LDC's?

A. No, He did not.

...

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2000 to 2004. Schedule WAR-5 also includes Value Line's projected 2005, 2006, and 2008-10 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use Southwest Water Company, (NASDAQ symbol SWWC) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 9 and 10) to multiply SWWC's earned return on common equity by its earnings retention ratio for each year in the 2000 to 2004 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on

Schedule WAR-5, Page 1, SWWC had sustainable internal growth that averaged 5.44 percent over the course of the 2000 to 2004 observation period. During this time frame, growth ranged from 7.22 percent in 2000, to 7.51 percent in 2001 but then fell to 5.91 percent in 2002. Internal growth continued to decline from 5.81 percent in 2003 to 0.75 percent in the final year of the observation period. Value Line's analysts are optimistic for the future, projecting growth of 2.14% for 2005, followed by steady increases of 3.32% and 7.64% in the 2006 and 2008-10 time frames. While a 5.00% to 5.50 percent rate of growth would appear to be reasonable, given the aforementioned information on the historic behavior of CWT's internal growth rate, projections for 17 percent on earnings and 9.00 percent on dividends by Value Line, lead me to believe that a 6.00% rate of growth appears to be within the realm of possibility for SWWC.

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that the pattern of share's outstanding increased from 13.33 million to 19.40 during the 2000 to 2004 time frame. Despite this share growth of 9.84 percent during the observation period, Value Line is predicting that this level will increase to only 19.50 million in 2005. This trend is expected to continue during the 2006 and 2008-10 time frames. Value Line's analysts are forecasting an increase of 21.50 million shares outstanding by the end of 2010. After weighing these projections, I believe that a 2.00% growth in shares is not unreasonable for SWWC. My final dividend growth rate estimate for SWWC is 7.30 percent (6.00 percent internal + 1.30 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample water utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 7.35 percent as displayed on page 1 of Schedule WAR-4.

Q. Did you use the same approach to determine an average dividend growth rate for the proxy comprised of natural gas LDC's?

A. Yes.

Q. What is your average dividend growth rate estimate using the DCF model for the sample natural gas utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 4.59 percent, which is also displayed on page 1 of Schedule WAR-4.

...

Q. How does your average dividend growth rate estimates on water companies compare to the growth rate data published by Value Line and other analysts?

A. In the case of the water companies, my estimate falls between the projections of analysts at both Zacks Investment Research, Inc. ("Zacks") and Value Line. Schedule WAR-6 compares my sustainable growth estimates with the five-year projections of both Zacks (Attachment D) and Value Line. The 7.35 percent estimate that I have calculated is 10 basis points lower than the projected 5-year EPS average of 7.45 percent for Zacks and 78 basis points lower than the 8.13 percent projection by Value Line (which is an average of EPS, DPS and BVPS). My 7.35 percent estimate is 346 basis points higher than the Value Line 5-year compound historical average also displayed in Schedule WAR-6. This indicates that investors are expecting increased performance from water utilities in the future. On balance, I would say my 7.35 percent estimate is a good representation of the growth projections that are available to the investing public.

Q. How does your average dividend growth rate estimates on natural gas LDC's compare to the growth rate data published by Value Line and other analysts?

A. In regard to the natural gas LDC's, my estimate falls 32 basis points below the projections of analysts at Zacks but only 1 basis point lower than

Value Line. However, as can also be seen on Schedule WAR-6, the 4.59 percent estimate that I have calculated is 34 basis points higher than the average of the projected 5-year EPS means of 4.91 percent for Zacks, the 4.60 percent projection by Value Line (which is an average of EPS, DPS and BVPS) and the five-year historical average of Value Line data on EPS, DPS and BVPS. In fact, my 4.59 percent estimate is 196 basis points higher than the Value Line 5-year compound historical average just noted. As with water companies, this indicates that investors are expecting increased performance from natural gas distribution companies in the future. In the case of the LDC's I would say that my 4.59 percent estimate, which is very close to Value Line's projections but somewhat lower than Zack's estimates, is a fairly good representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. For both the water companies and the natural gas LDC's I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's January 27, 2006 Ratings and Reports water services industry update and Value Line's December 16, 2005 Ratings and Reports Natural Gas (Distribution) update. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period December 27, 2005 to February 17, 2006.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the water and natural gas companies included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.49 percent for the water companies and 9.29 percent for the natural gas LDC's.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[8], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics with Merton Miller and Harry Markowitz for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[9] In this

[8] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[9] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns

regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

where:	k	=	cost of capital of a given security,
	r_f	=	risk-free rate of return,
	$ß$	=	beta coefficient, a statistical measurement of a security's systematic risk,

on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day U.S. Treasury Bill ("T-Bill") rate.[10] This resulted in a risk-free (r_f) rate of return of 4.37 percent.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[11] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary

[10] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from January 13, 2006 to February 17, 2006.

[11] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2004 as the proxy for the market rate of return (r_m). The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 6.03 percent (10.40% - 4.37% = <u>6.03%</u>). The risk premium that results by using the arithmetic mean calculation for r_m is 8.03 percent (12.40% - 4.37% = <u>8.03%</u>).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of January 27, 2006 for the water companies and December 16, 2005 for the natural gas LDC's. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the service providers included in my water company sample ranged from 0.70 to 0.80 with an average beta of 0.75. The beta coefficients for the LDC's included in my natural gas sample ranged from 0.65 to 0.85 with an average beta of 0.78.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 8.89 percent for the water companies and 9.08 percent for the natural gas LDC's. My calculation using the arithmetic mean results in an average expected return of 10.39 percent for the water companies and 10.64 percent for the natural gas LDC's. Although there is some debate on this point, I believe that the consensus among financial analysts appears to be that the arithmetic mean is the better of the two averages. For this reason, I believe that the 10.39 percent estimate for water and the 10.64 percent figure for gas are the better checks on the results of my respective DCF analyses for water and gas.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF (Water Sample)	9.49%
DCF (Natural Gas Sample)	9.29%
CAPM (Water Sample)	8.89% – 10.39%
CAPM (Natural Gas)	9.08% – 10.64%

Based on these results, my best estimate of an appropriate range for the cost of equity is from 8.89 percent to 10.64 percent. My final recommendation is a 9.49 percent return for BMSC's cost of equity capital.

...

Q How did you arrive at your recommended 9.49 percent cost of common equity?

A. My recommended 9.49 percent cost of common equity is the result of my DCF analysis for water companies, which is the higher of my two DCF estimates.

Q. Is this the method that you have typically used to determine the cost of equity capital in prior rate case proceedings?

A. Typically yes. With a few exceptions I have generally used the results obtained from the DCF model as a basis for my final recommended cost of equity capital while using the CAPM as a check on DCF results.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are investing in non-regulated entities also.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. Economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[12] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-

[12] The interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy over the last five years?

A. The U.S. economy entered into a recession around the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve Chairman was cutting rates in the hope of avoiding the recession that the U.S. is still in the process of recovering from.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates, moves which indicated that the worst may be over and that the current recession might have bottomed out during the last quarter of 2001, a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC stated "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.'"[13]

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25

[13] Wolk, Martin, "Fed leaves short-term rates unchanged," MSNBC, January 28, 2004.

percent. Between June 29, 2004 and January 31, 2006, the FOMC has raised the federal funds rate thirteen more times to its current level of 4.50 percent (the next scheduled meeting of the FOMC will be on March 28, 2006). The FOMC's January 31, meeting was also the final meeting for retiring Chairman Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the chairman of the President's Council of Economic Advisers and a former Fed governor from 2002 to 2005, was confirmed by the U.S. Senate to be the new Fed chief.

Q. What has been the reaction to the latest Fed action on interest rates?

A. As expected, banks have followed the Fed's lead once again and have boosted the prime rate to its current level of 7.50 percent. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy[14]. In other words, the Fed was trying to head off inflation *before* it became a problem.

Since it began increasing the federal funds rate in June 2004, the Federal Reserve had stated that it would increase rates at a "measured" pace.

[14] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates resulted in financial turmoil, which contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[15].

Q. Putting this all into perspective, how have the Fed's actions over the past five years affected benchmark rates?

A. Despite recent increases by the FOMC, interest rates and yields on U.S. Treasury instruments are still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. Despite the recent increases in the federal funds rate, the federal discount rate (the rate charged to member banks) has fallen from 5.73 percent in 2000, to its present level of 5.50 percent.

Q. What has been the trend in other leading interest rates over the last year?

A. As of February 9, 2006, all of the leading interest rates have moved up. The prime rate has increased from 5.50 percent a year ago to a current level of 7.50 percent. The benchmark federal funds rate, just discussed, has increased from 2.50 percent, in February 2005, to its current level of

[15] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

4.50 percent (the result of the fourteen quarter point increases noted earlier). The yields on all maturities of U.S. Treasury instruments have increased over the past year. Both the 30-year and 30-year zero Constant Maturity rates have reversed their earlier trends of falling as short-term rates were rising, a condition that had been described by former Chairman Greenspan as a "conundrum"[16], thus creating the flat yield curve that currently exists (Attachment E). The 91-day T-bill rate, used in my CAPM analysis, has increased from 2.51 percent, in February 2005, to 4.51 percent today. The 1-Year Treasury Constant Maturity rate has also increased from 2.93 percent over the past year to 4.66 percent today. Again, these levels are still low when they are compared with yields during the early nineties displayed on Schedule WAR-8.

Q. How have economists and members of the investment community viewed the Fed's rate actions since June 2004?

A. The change in the Fed's language from "considerable period" to "patient" to "measured," that have been noted through the course of my testimony, has pretty much summed up the Fed's course of action during the economic recovery that is still in progress. In his October 2004 column for Wells Capital Management's ("Wells") Monthly Market Outlook publication, Senior Economist Gary E. Schlossberg viewed the Fed's credit tightening action as a trend that would likely continue barring an unraveling of the

[16] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

economic recovery, a major disruption in the financial markets or a renewed threat of declining prices. Mr. Schlossberg believed then that the Fed was determined to engineer a fundamental shift from its past policy of "aggressive accommodation" to what he considered to be a more "neutral" policy stance (determined by both the rate of inflation and an additional "premium" of possibly 1.00 percent to 1.50 percent) via a series of rapid fire quarter-point (i.e. 25 basis points) increases that will result in a federal funds rate of 4.00 percent to 4.50 percent by the end of 2005. Mr. Schlossberg's expectation of future incremental increases in the federal funds rate was also shared at the time by Mickey Levy, Chief Economist for Bank of America, and by Value Line analysts. In the October 1, 2004 edition of Value Line's "Selection & Opinion" publication, Value Line's analysts stated that they believed that the Fed was following a prudent course. In their opinion the Fed's interest rate cutting helped to avoid a more serious recession and the Fed's present course of action will help to insure that the current upturn in the economy is sustained while keeping inflation low and under control at the same time.

Q. What is the current outlook for interest rates, inflation, and the economy?

A. The views expressed by Messrs Levy and Schlossberg during the last quarter of 2004 have only been off target by about three months. A recent article[17] in the February 1, 2006 edition of The Wall Street Journal reported that a Fed statement accompanying the news of the latest rate hike signaled that another rate increase is still on the table and, that at this point, it appears that any further increases will depend on incoming economic data. If the Fed continues its trend of raising rates in 25 basis point increments under incoming Chairman Bernanke, the federal funds rate should level off at either 4.50 percent or 4.75 percent within the first quarter of 2006.

According to analysts and economists at Value Line and Wells Capital Management, the overall outlook for economic growth, and the current low interest rate environment, appears to be good despite a moderate pace of GDP growth and higher oil prices. In their most recent Selection & Opinion outlook published on Friday, February 17, 2006, Value Line analysts stated the following:

> "We think the economy will settle into a modest, albeit sustainable, growth course over the balance of 2006. Underpinning this prospective growth of 3.0%-3.5% should be solid levels of industrial production and capital goods activity, stable trends in consumer spending, and further gains in personal income and employment. Arguing against stronger growth will be high oil prices and generally softening demand for housing.

The following quote[18] by Wells Capital management's Chief Investment Strategist, James W. Paulsen, Ph.D., had this to say:

> "While we believe that the stock market will be dictated by the pace of real economic growth this year, the bond market and Fed actions will depend on the direction of core consumer price inflation. Until now, Fed policy has been aimed at reversing the

[17] Ip, Greg, "Fed Lifts Rate by Quarter Point, Casts Doubt on More Increases," The Wall Street Journal, February 1, 2006.
[18] Wells Capital Management's Economic and Market Perspective, January 2006, Page 1.

> emergency discount and returning short-term interest rates back to a neutral range. Future policy actions will now depend primarily on inflation evidence. Throughout this recovery the bond market has consistently shown a newfound attitude – 'strong real economic growth doesn't scare me, only evidence of actual core inflation will get me to raise yields'."

Q. How has the water industry segment of the U.S. economy fared recently?

A. In his January 27, 2006 update on the water services industry, Value Line analyst Andre Costanza stated that earnings for the water utility industry as a whole continued to lag the earnings of most industrial companies during 2005. Mr. Costanza attributes this problem to a combination of rainy weather and rising infrastructure costs. Although none of the water company stocks followed by Value Line offer attractive capital gains, according to Mr. Costanza, they do remain attractive to income-oriented investors. Mr. Costanza noted that water utility stocks have had a long history of generating steady streams of income and that AWR and CWT both offer above-average dividend yields that should, based on Value Line's projections, continue over the long run (Attachment B).

Q. What has been the trend in Value Line's return on common equity projections for the water utility industry over the last six years?

A. Up until this year, and with the exception of 2003, Value Line's analysts have been making downward projections on water industry book returns on common equity ("ROE"). The following is a summary of Value Line's water utility industry composite statistics on ROE, over the aforementioned period, which are exhibited in Attachment F of my testimony:

Value Line Published Projected Returns 2000 – 2005

	2000	**2001**	**2003-05**
Value Line ROE Projection – Nov. 3, 2000	11.0%	11.0%	12.0%
	2001	**2002**	**2004-06**
Value Line ROE Projection – Nov. 2, 2001	10.5%	11.0%	11.5%
	2002	**2003**	**2005-07**
Value Line ROE Projection – Nov. 1, 2002	10.0%	10.5%	11.5%
	2003	**2004**	**2006-08**
Value Line ROE Projection – Oct. 31, 2003	10.0%	11.0%	12.0%
	2004	**2005**	**2007-09**
Value Line ROE Projection – Oct. 29, 2004	9.5%	9.5%	10.0%
	2005	**2006**	**2008-10**
Value Line ROE Projection – Oct. 28, 2005	11.0%	11.0%	11.5%

Value Line Published Actual Returns 2001 - 2005

	2001	**2002**	**2003**	**2004**
Value Line historic Returns – Oct. 28, 2005	10.7%	11.2%	8.8%	10.7%

In addition to the downward trend in projections that I just addressed, the above summary also illustrates the fact that Value Line's analysts have been somewhat more optimistic in their forward-looking one-year and long-term projections. As can be seen below, Value Line's analysts have been somewhat high in their coming year projections on ROE.

Year	Value Line Projected	Actual Book Return on ROE	Difference
2001	11.0%	10.7%	-30 Basis Points
2002	11.0%	11.2%	20 Basis Points
2003	10.5%	8.8%	-170 Basis Points
2004	11.0%	10.7%	-30 Basis Points

As can be seen above, with the exception of the 2002 operating period, Value Line's analyst's projections on water utility ROE's from one year out were 30 to 170 basis points higher than the actual returns booked by the water utilities. This is why I do not rely on the face value of analyst's projections and only use Value Line's and Zack's projections as guides in developing my growth estimates for the DCF model.

Q. Please summarize how the economic data just presented relates to BMSC.

A. If incoming Fed Chairman Benanke continues to keep inflation in check, and keep it contained within in his preferred range of 1 to 2 percent[19], BMSC could look forward to relatively stable and even possibly declining prices for goods and services, which in turn means that BMSC can expect its present operating expenses to either remain stable or possibly decline in the coming years. Lower interest rates would also benefit BMSC in regard to any short or long-term borrowing needs that the Company may have. Lower interest rates, would further help to accelerate growth in new

[19] Ip, Greg, "Fed Minutes Indicate Inflation Still a Worry for Some Officials, " The Wall Street Journal, February 22, 2006.

construction projects and home developments in the Company's service territories, and may result in new revenue streams to BMSC.

Q. After weighing the economic information that you've just discussed, do you believe that the 9.49 percent cost of equity capital that you have estimated is reasonable for BMSC?

A. I believe that my recommended 9.49 percent cost of equity will provide BMSC with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards), continued growth in new housing construction (attributed to historically low interest rates), and a low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return. The results that I have obtained are consistent with Value Line's view that the water utility stocks included in my proxy "offer an above average dividend yield."

CAPITAL STRUCTURE

Q. Have you reviewed BMSC's testimony regarding the Company's proposed capital structure?

A. Yes, I have.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a capital structure comprised of 100 percent common equity. This capital structure excludes long-term debt issued by the Algonquin Fund to BMSC[20]. BMSC argues in this case that, because it has treated the Company's debt service costs as an annual operating lease expense, the underlying debt issuances should be excluded from the capital structure. RUCO is not recommending this operating lease treatment, and therefore it is appropriate to reflect the debt issuance in the capital structure.

Q. Is RUCO recommending that the Commission continue to treat the purchased treatment capacity as an operating lease?

A. No. RUCO witness Marylee Diaz Cortez, CPA, is recommending that the purchased treatment capacity be treated as a utility asset and that it be included in BMSC's rate base as utility plant-in-service. Accordingly, I have made an adjustment to remove the Company-proposed $189,622 operating expense, which recovers the debt service on the purchased treatment capacity.

Q. What capital structure are you proposing?

A. I am recommending a capital structure comprised of 56 percent common equity and 44 percent long-term debt.

[20] This adjustment is discussed in detail in the direct testimony RUCO witness Marylee Diaz Cortez, CPA

Q. How did you arrive at your recommended level of Common equity?

A. My recommended capital structure includes the Company-proposed test year adjusted level of $1,498,949 in common equity.

Q. How did you determine your recommended level of long-term debt?

A. The $1,201,726 level of long-term debt represents the general ledger balance of inter-company loans that are identified on BMSC's balance sheet as payables to associated companies, which along with my recommended level of common equity, financed the Company's test year level of plant-in-service and the purchased treatment capacity asset, that Ms. Diaz Cortez is recommending rate base treatment for, during the test year.

Q. Will the opportunity exist for BMSC to recover the Company's investment in the purchased treatment capacity under the treatment that RUCO is proposing?

A. Yes. BMSC will have an opportunity to recover the Company's invested capital in the purchased treatment capacity in the same manner that the Company will recover all of its other invested capital under normal ratemaking practice.

Q. Please describe the payables to associated companies that you have included in the long-term debt portion of your recommended capital structure.

A. The payables to associated companies represent inter-company loans, between the Company and Algonquin Water Resources of America, Inc., as evidenced by three promissory notes that were entered into on March 16, 2001, at the time of Algonquin Power's acquisition of BMSC.

Q. How did you arrive at your recommended cost of 9.40 percent for the payables to associated companies?

A. My recommended 9.40 percent cost of debt is the same cost of debt that the Company's consultant used to calculate the operating lease expense figure exhibited in Schedule C of BMSC's Application.

Q. Is the Company-proposed capital structure in line with industry averages?

A. No. The Company-proposed capital structure is much heavier in equity than the capital structures of the other water companies included in my cost of capital analysis (Schedule WAR-9). The capital structures for those utilities averaged 50.1 percent for debt and 49.9 percent for equity (49.8 percent common equity + 0.1 percent preferred equity).

...

Q. In terms of risk, how does the Company-proposed capital structure compare to the water utilities in your sample?

A. The water utilities in my sample, from which I derived an estimated cost of common equity of 9.49 percent, would be considered as having a higher level of financial risk (i.e. the risk associated with debt repayment) because of their higher levels of debt. The additional financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the 9.49 percent cost of equity derived in my DCF analysis is applicable to companies that are more leveraged and, theoretically speaking, riskier than a utility with no debt in its capital structure.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.00 percent cost of equity capital proposed by the Company's cost of capital witness is 151 basis points higher than the 9.49 percent cost of equity capital that I am recommending.

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. As explained earlier, the Company has proposed a weighted cost of capital of 11.00 percent. This composite figure is the result of the total absence of debt. The Company-proposed 11.00 percent weighted cost of capital is 155 basis points higher than the 9.45 percent weighted cost that I am recommending which was derived from water utilities in my sample which are perceived as having financial risk as a result of their leveraged capital structures.

COMMENTS ON BMSC'S COST OF EQUITY CAPITAL TESTIMONY

Q. Who estimated the Company-proposed cost of equity capital?

A. Mr. Thomas M. Bourassa (who I noted earlier in my testimony) estimated the Company-proposed cost of equity capital for BMSC.

Q. Briefly describe Mr. Bourassa's testimony.

A. As was discussed in the last section of my testimony, Mr. Bourassa is proposing a final cost of common equity estimate of 11.00 percent for BMSC based on the results of his cost of equity analysis, which ranged from 9.10 percent to 12.70 percent. His weighted cost of capital of 11.00 percent is the result of his proposed capital structure, which excluded all of BMSC's linter-company loans used to finance the purchased treatment capacity from the City of Scottsdale. Mr. Bourassa believes that a higher cost of equity is merited for a number of reasons including the financial risk associated with the inter-company loans that he excluded from the Company-proposed capital structure.

Q. Do you agree with Mr. Bourassa's rationale that even though the inter-company loans are not included in the Company's capital structure, the Company still requires a higher cost of common equity that takes financial risk, normally associated with long-term debt obligations to bondholders or financial institutions, into consideration?

A. No I do not agree with Mr. Bourassa's rationale on this matter. Mr. Bourassa takes the position that the Company's inter-company loans still have an impact on BMSC's cost of common equity even though he has excluded the loans from the Company's capital structure. If the Commission were to treat the purchased treatment capacity as an operating lease, as opposed to a plant-in-service asset as RUCO is recommending, BMSC will recover the inter-company payable on a dollar-for-dollar basis in rates as an operating expense. This would remove any financial risk associated with the inter-company loans assuming there were any financial risks to begin with on an inter-company payable as opposed to a bond issuance or a third party loan. In short, the Company wants the best of all worlds. The Company seeks to fully recover the inter-company loan on a dollar-for-dollar basis as an operating expense, and also seeks a higher return on common equity, attributable to financial risk, when it is proposing a capital structure that has no debt and should therefore have no financial risk whatsoever.

Q. What cost of common equity and capital structure would you recommend if the Commission were to adopt the Company-proposed operating lease treatment?

A. I would recommend a lower cost of common equity that reflects the absence of financial risk. This could be achieved by either making a direct reduction to the 9.49 percent cost of common equity derived from my DCF analysis, as I did in a prior case involving Rio Rico Utilities, Inc, or by applying a hypothetical capital structure, as I did in the recent Southwest Gas Corporation Case. Another approach to achieve the appropriate result would be to adopt the capital structure and cost of debt of BMSC's parent, the Algonquin fund. As can be seen on pages 1 and 2 of Schedule WAR-1, this would result in a capital structure comprised of 57 percent equity and 43 percent debt, a weighted cost of debt of 8.16 percent and a weighted cost of capital of 8.92 percent (assuming the Commission adopts my recommended 9.49 percent cost of common equity).

Q. How would you respond to the argument that the Algonquin Fund long-term debt was not used to directly finance the assets of BMSC?

A. The same argument could be made for any hypothetical capital structure that uses a cost of debt based on the going rate of interest for utility bond issues. In this case, the weighted cost of the Algonquin Fund's long-term debt liabilities (i.e. the debt incurred by the companies that make up the

Algonquin Fund) would be fairer, since it would include the actual costs of debt obligations that were incurred by Arizona utilities (i.e. Litchfield Park Service Company and Bella Vista Water Company). While such an argument could certainly be made against the capital structure approach that I am suggesting here, it would neither address nor solve the need to calculate a downward adjustment to the 9.49 percent cost of common equity that I derived from my DCF analysis. This same capital structure issue was addressed in the Rio Rico Utilities, Inc., rate case, in which the Commission recognized the fact that a downward adjustment was reasonable. This is evidenced in the Commission's Decision on Rio Rico Utilities, Inc., which states the following:

> Based on the entirety of the record, we find that Rio Rico's cost of equity to be 8.7 percent which is approximately the midpoint between Staff's updated estimate (8.6 percent) and RUCO's recommendation (8.83 percent). However, the Company's capital structure is comprised entirely of equity, at a time when the cost of debt is low. As a result, ratepayers are penalized by the Company's choice of a capital structure consisting of higher cost equity. Although we are not using a hypothetical capital structure in this case, we believe that recognition of this imbalance should be reflected in the authorized rates of return for the wastewater division which experienced an operating loss during the test year.

Using the Algonquin Fund's capital structure, which is heavier in equity, would be more favorable to the Company since it would produce a higher weighted cost of capital than what a hypothetical capital structure using the average capital structure of my sample water companies and recent yields on utility bonds (ranging from 5.69 percent to 6.05 percent) would provide.

Q. Is it common practice to use the capital structure of a utility's parent company in rate cases?

A. Yes. The best example is the Citizens Utilities case[21], which I noted in the DCF section of my testimony. In that case RUCO recommended that the Commission adopt a hypothetical capital structure of 50 percent common equity and 50 percent debt, however, the Commission adopted ACC Staff and Citizens' recommendation to use Citizens' actual consolidated capital structure of 62 percent common equity and 38 percent long-term debt. In arriving at its decision to use the actual consolidated capital structure, the Commission concluded that Citizens' Arizona gas and electric divisions had no stand alone capital structures of their own and that all of the capital was provided from Citizens. That is just as true in this case since all of the capital, including the capital associated with the inter-company loans, has come from the Algonquin Fund.

Q. Does the fact that BMSC is owned by a mutual fund merit any different approach for establishing a capital structure than the manner in which a capital structure would be established for a holding company-owned or developer-owned utility?

A. No, I do not believe so. At the end of the day the approach taken by the Algonquin Fund is simply one more form of investing in and owning an economic entity or a financial instrument. In this case we're talking about

[21] Decision No. 58664, dated June 16, 1994

a collection of utilities or utility related businesses from which the investors, or unit holders if you will, expect to realize a rate of return on.

Q. Are there any other reasons why you believe that the Commission should adopt your recommended capital structures and weighted costs of capital?

A. Yes. As I explained in my direct testimony on required revenue, the Company's parent has a large measure of control over the amounts that are charged for contractual service expenses. Given the fact that the Company's parent has direct control on any markup for performing these services, the potential exists to manipulate BMSC's bottom line operating income. For this reason, I believe that the Commission should adopt a conservative rate of return for the Company.

Q. What methods did Mr. Bourassa use to arrive at his cost of common equity?

A. Mr. Bourassa used the DCF method and the risk premium method. His final estimate of 11.00 percent weighs the results obtained with these methodologies with actual returns, authorized returns and analyst's projections on returns on book equity over the 2005 – 2008 operating periods.

Q. Did you conduct a risk premium study?

A. No I did not.

Q. Do you agree with Mr. Bourassa's assertions that BMSC is riskier because it is smaller than the utilities included in his sample and operates in the Arizona Jurisdiction?

A. No. Both of these arguments have been advanced by a number of utility witnesses over the years and the Commission has soundly rejected both arguments in every case that I have been involved in.

Q. Please comment on Mr. Bourassa's comments on the reliability of DCF results because of rising utility stock prices.

A. A similar argument can be made for the CAPM methodology, which is dependent on interest rates that have increased over the past year. Any methodology for determining the cost of equity capital is subject to fluctuating economic conditions, such as stock prices and interest rates, at any given point in time. That is why more than one methodology is used in making a final estimate on what the cost of common equity for a utility is. I believe that varying economic conditions and their effects on the estimation of a cost of capital are a fact of life for entities that choose to engage in the regulated utility business. At the end of the day, utilities such as BMSC choose when to file for rates and if the possibility exists that current economic conditions may have a negative impact on their desired rate of return they can refrain from filing for rates.

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Mr. Bourassa conducted his?

A. Yes, as can be seen above, Mr. Bourassa conducted three separate DCF analyses. Each of his DCF analyses uses a sample proxy of six water providers. His first DCF analysis uses a one-step constant growth model that uses analyst's estimates of long-term EPS growth for the growth (g) component in the model. His second DCF analysis is also a one-step constant growth model, similar to the one that I used, which includes Mr. Bourassa's sustainable growth (br + sv) estimates for the growth component in the model. Mr. Bourassa's third DCF analysis is a variation on the two-step or multi-stage growth DCF model.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Mr. Bourassa?

A. Primarily because the growth rate component that I estimated for my single-stage model takes into consideration both the near-term and long-term GDP growth rate projections that Mr. Bourassa used in his multi-stage model. This being the case, I saw no need to conduct a separate DCF analysis. During a recent rate case involving the Paradise Valley Water District[22], Dr. Michael J. Vilbert, the cost of capital consultant for Arizona-American Water Company, took the position that the long-term GDP projections used in the multi-stage DCF model mitigates the effect of

[22] Docket No. W-01303A-05-0405

optimism bias, which is a tendency on the part of analysts to make overly optimistic growth estimates. In support of his position, Dr. Vilbert cited of a 2003 study[23], which concluded that there is little forecastability in earnings estimates over long horizons and that analysts' estimates tend to be overly optimistic. This situation was illustrated earlier in my testimony using Value Line estimates versus actual realized returns on book equity. As I also pointed out earlier in my testimony, the approach that I use takes optimism bias into consideration.

Q. What is the difference between your DCF results and Mr. Bourassa's first DCF result?

A. The 9.49 percent cost of common equity derived in my DCF analysis, that uses an average of four sample water companies, is 111 basis points lower than the 10.60 percent midpoint figure derived in Mr. Bourassa's one-step DCF analysis, which is an average of six sample water companies (as exhibited in Schedule D-4.9 of the Company's Application).

Q. Please explain why your 9.49 percent DCF result is 111 basis points lower than the 10.60 percent result produced by Mr. Bourassa's one-step DCF model.

A. As I pointed out earlier in my testimony, Mr. Bourassa utilized three small to mid cap water utilities that are not traded as frequently as the

[23] L. K. C. Chan, J. Karceski, and J. Lakonishok, 2003, "The Level and Persistence of Growth Rates, " Journal of Finance 58(2): 643-684.

companies in my sample. Mr. Bourassa's sample did not include results for SWWC either. Because of this we do not have an apples to apples comparison. When the three water companies that we do have in common are compared against each other, Mr. Bourassa's model produces a figure of 11.1 percent or 161 basis points higher than the 9.49 percent figure produced by mine. The comparison is still not an accurate one because Mr. Bourassa relied entirely on analyst's EPS growth estimates at face value whereas my model relied on my estimates of sustainable growth using analyst's projections as a guide. His average stock prices, (P_0) of the DCF formula ($k = (D_1 \div P_0) + g$), are spot prices which were observed on July 29, 2005 versus the eight-week average that I used. The difference between the closing stock prices used in my analysis and Mr. Bourassa's analysis are as follows:

	Rigsby	**Bourassa**	**Difference**
AWR	$31.72	$31.07	$0.65
CWT	$40.13	$40.00	$0.13
WTR	$27.83	$30.78	$2.95

In the case of WTR, the lower 8-week price that I used reflects a 4 for 3 stock split which occurred in the last week of 2005.

Q. What is the difference between your DCF estimate and Mr. Bourassa's second DCF analysis using sustainable growth estimates?

A. Mr. Bourassa's model produced a midpoint estimate of 11.20 percent, which is 171 basis points higher than the result 9.49 percent figure produced by my DCF model. In addition to the differences that I pointed out previously regarding the utilities used in our samples and the differences in the dividend yield portion of the model, Mr. Bourassa again relies solely on the higher estimates of value line analysts for his estimates of br and s. Unlike my estimate of the v component of the model, Mr. Bourassa's estimate of v fails to recognize that the market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital. This results in a higher figure for the v component of the growth estimate.

Q. Didn't you state earlier in your testimony that you did not use utilities that are followed in Value Line's Small and Mid Cap Edition because Value Line's analysts do not provide forward-looking information on long-term estimates of share growth?

A. Yes I did. These projections are used to develop an input for the sv component in my DCF model.

Q How did Mr. Bourassa deal with this situation in his sustainable growth model?

A. Mr. Bourassa was unable to calculate an actual sv estimate for Connecticut Water Service, Inc., Middlesex Water Company and SJW Corp. Instead of eliminating these companies from the analysis, he simply substitutes an average of his growth estimates (br + sv) for the other three utilities that were included in both of our samples.

Q. What is the difference between your DCF result and Mr. Bourassa's two-step or multi-stage growth model DCF result?

A. The 9.49 percent cost of common equity derived in my DCF analysis (that uses four sample water companies) is 61 basis points lower than the 10.10 percent midpoint estimate derived in Mr. Bourassa's two-step DCF analysis. This version of the DCF produced the lowest midrange result of all the versions employed by the Company's witness. Mr. Bourassa used a long-term GDP growth estimate in the second stage component of the model, which as I discussed earlier, is believed to help mitigate the effects of optimism bias among securities analysts. Once again Mr. Bourassa used his same of six water companies.

...

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Bourassa or any other witness for BMSC constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on BMSC?

A. Yes, it does.

Appendix 1

Qualifications of William A. Rigsby

Qualifications of William A. Rigsby

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Revenue Auditor II
Arizona Department of Revenue
Corporate Income Tax Audit Unit
Phoenix, Arizona
November 1993 – October 1994

Tax Examiner Technician I
Arizona Department of Revenue
Transaction Privilege Tax Audit Unit
Phoenix, Arizona
July 1991 – November 1993

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase

BLACK MOUNTAIN SEWER CORPORATION
DOCKET NO. SW-02361A-05-0657
TABLE OF CONTENTS TO SCHEDULES WAR

WEIGHTED COST OF CAPITAL ASSUMING THE COMMISSION REJECTS THE COMPANY-PROPOSED OPERATING LEASE

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	LONG-TERM DEBT	$ -	$ 1,201,726	$ 1,201,726	44.00%	9.40%	4.14%
2	COMMON EQUITY	1,498,949	-	1,498,949	56.00%	9.49%	5.32%
3	TOTAL CAPITALIZATION	$ 1,498,949	$ 1,201,726	$ 2,700,675	100.00%		
4	**WEIGHTED COST OF CAPITAL**						9.45%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): TESTIMONY, WAR
COLUMN (F): COLUMN (D) x COLUMN (E)

WEIGHTED COST OF CAPITAL ASSUMING THE COMMISSION ADOPTS THE COMPANY-PROPOSED OPERATING LEASE

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) RUCO WEIGHTED COST
1	LONG-TERM DEBT	43.00%	8.16%	3.51%
2	COMMON EQUITY	57.00%	9.49%	5.41%
3	TOTAL CAPITALIZATION	100.00%		
4	**WEIGHTED COST OF CAPITAL**			8.92%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR-1, PAGE 2 & TESTIMONY, WAR
COLUMN (C): COLUMN (A) x COLUMN (B)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
COST OF CAPITAL SUMMARY

DOCKET NO. SW-02361A-05-0657
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WEIGHTED COST OF DEBT ASSUMING THE COMMISSION ADOPTS THE COMPANY-PROPOSED OPERATING LEASE

LINE NO.	(A) DESCRIPTION	(B) MATURITY DATE	(C) END OF TEST YEAR BALANCE ($OOO's) CANADIAN	(D) INTEREST RATE	(E) TEST YEAR BALANCE RATIOS	(F) WEIGHTED COST OF DEBT
1	SENIOR DEBT LONG SAULT RAPIDS	DEC - 2008	$ 43,310,000	10.20%	33.13%	3.38%
2	SENIOR DEBT CHUTE FORD	APR - 2020	5,473,000	11.55%	4.19%	0.48%
3	SANGER BONDS	SEP -2020	23,109,000	10.00%	17.68%	1.77%
4	KMS CONVERTIBLE DEBENTURES	JUN - 2004	-	-	0.00%	0.00%
5	BELLA WATER LOAN MATURING IN 2017	DEC - 2017	170,000	6.10%	0.13%	0.01%
6	BELLA WATER LOAN MATURING IN 2020	MAR - 2020	2,252,000	6.26%	1.72%	0.11%
7	LITCHFIELD PARK SERVICES COMPANY 1999 IDA BONDS	OCT - 2023	6,324,000	5.87%	4.84%	0.28%
8	LITCHFIELD PARK SERVICES COMPANY 2001 IDA BONDS	OCT - 2031	10,138,000	6.71%	7.76%	0.52%
9	REVOLVING CREDIT FACILITY	AUG - 2006	30,000,000	4.56%	22.95%	1.05%
10	OTHER LONG-TERM LIABILITIES	VARIOUS	241,000	12.40%	0.18%	0.02%
11	CONVERTIBLE DEBENTURES	JUL - 2011	-	6.65%	0.00%	0.00%
12	JOLIET SUBSIDY LOAN	JUL - 2017	3,942,000	9.50%	3.02%	0.29%
13	MELO ROOS	OCT - 2011	1,649,000	4.75%	1.26%	0.06%
14	CUSTOMER DEPOSITS	N/A	2,850,000	6.00%	2.18%	0.13%
15	CAPITAL LEASES	VARIOUS	853,000	7.64%	0.65%	0.05%
16	OTHER LONG-TERM LIABILITIES	VARIOUS	400,000	4.81%	0.31%	0.01%
17						
18	TOTALS		$ 130,711,000		100.00%	
19						
20	**WEIGHTED COST OF DEBT**					8.16%

REFERENCES:
COLUMN (A) THRU (D): RUCO DATA REQUESTS 3.6, 3.7, 3.8 AND 3.9
COLUMN (E): COLUMN (C) ÷ LINE 22 COLUMN (C)
COLUMN (F): COLUMN (D) x COLUMN (E)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DCF COST OF EQUITY CAPITAL

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AWR	AMERICAN STATES WATER CO.	2.84%	+	7.60%	=	10.43%
2	CWT	CALIFORNIA WATER SERVICE GROUP	2.84%	+	6.81%	=	9.65%
3	SWWC	SOUTHWEST WATER COMPANY	1.33%	+	7.30%	=	8.63%
4	WTR	AQUA AMERICA, INC.	1.55%	+	7.71%	=	9.26%
5	**WATER COMPANY AVERAGE**						9.49%
6	CGC	CASCADE NATURAL GAS CORPORATION	4.85%	+	2.20%	=	7.04%
7	KSE	KEYSPAN CORP.	5.03%	+	3.42%	=	8.46%
8	LG	LACLEDE GROUP, INC.	4.43%	+	3.39%	=	7.82%
9	NWN	NORTHWEST NATURAL GAS CO.	3.91%	+	5.32%	=	9.23%
10	PGL	PEOPLES ENERGY CORPORATION	5.99%	+	3.64%	=	9.63%
11	SJI	SOUTH JERSEY INDUSTIES, INC.	5.97%	+	7.15%	=	13.12%
12	SWX	SOUTHWEST GAS CORPORATION	3.03%	+	6.54%	=	9.56%
13	WGL	WGL HOLDINGS, INC.	4.37%	+	5.09%	=	9.46%
16	**NATURAL GAS LDC AVERAGE**						9.29%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DIVIDEND YIELD CALCULATION

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AWR	AMERICAN STATES WATER CO.	$0.90	÷	$31.72	=	2.84%
2	CWT	CALIFORNIA WATER SERVICE GROUP	1.14	÷	40.13	=	2.84%
3	SWWC	SOUTHWEST WATER COMPANY	0.20	÷	15.09	=	1.33%
4	WTR	AQUA AMERICA, INC.	0.43	÷	27.83	=	1.55%
5	**WATER COMPANY AVERAGE**						2.14%
6	CGC	CASCADE NATURAL GAS CORPORATION	$0.96	÷	$19.81	=	4.85%
7	KSE	KEYSPAN CORP.	1.82	÷	36.17	=	5.03%
8	LG	LACLEDE GROUP, INC.	1.38	÷	31.17	=	4.43%
9	NWN	NORTHWEST NATURAL GAS CO.	1.38	÷	35.29	=	3.91%
10	PGL	PEOPLES ENERGY CORPORATION	2.18	÷	36.41	=	5.99%
11	SJI	SOUTH JERSEY INDUSTIES, INC.	1.75	÷	29.34	=	5.97%
12	SWX	SOUTHWEST GAS CORPORATION	0.82	÷	27.07	=	3.03%
13	WGL	WGL HOLDINGS, INC.	1.33	÷	30.50	=	4.37%
16	**NATURAL GAS LDC AVERAGE**						4.70%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 01/27/2006 (WATER COMPANIES) AND 12/16/2005 (NATURAL GAS LDC's).
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 12/27/2005 TO 02/17/2006 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AWR	AMERICAN STATES WATER CO.	6.00%	+	1.60%	=	7.60%
2	CWT	CALIFORNIA WATER SERVICE GROUP	4.00%	+	2.81%	=	6.81%
3	SWWC	SOUTHWEST WATER COMPANY	6.00%	+	1.30%	=	7.30%
4	WTR	AQUA AMERICA, INC.	6.00%	+	1.71%	=	7.71%
5	**WATER COMPANY AVERAGE**						7.35%
6	CGC	CASCADE NATURAL GAS CORPORATION	1.75%	+	0.45%	=	2.20%
7	KSE	KEYSPAN CORP.	3.00%	+	0.42%	=	3.42%
8	LG	LACLEDE GROUP, INC.	3.00%	+	0.39%	=	3.39%
9	NWN	NORTHWEST NATURAL GAS CO.	5.00%	+	0.32%	=	5.32%
10	PGL	PEOPLES ENERGY CORPORATION	3.00%	+	0.64%	=	3.64%
11	SJI	SOUTH JERSEY INDUSTIES, INC.	6.00%	+	1.15%	=	7.15%
12	SWX	SOUTHWEST GAS CORPORATION	6.00%	+	0.54%	=	6.54%
13	WGL	WGL HOLDINGS, INC.	5.00%	+	0.09%	=	5.09%
16	**NATURAL GAS LDC AVERAGE**						4.59%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	AWR	AMERICAN STATES WATER CO.	3.25%	x	{ [((1.98) + 1) ÷ 2] - 1 }	=	1.60%
2	CWT	CALIFORNIA WATER SERVICE GROUP	4.00%	x	{ [((2.40) + 1) ÷ 2] - 1 }	=	2.81%
3	SWWC	SOUTHWEST WATER COMPANY	2.00%	x	{ [((2.30) + 1) ÷ 2] - 1 }	=	1.30%
4	WTR	AQUA AMERICA, INC.	1.00%	x	{ [((4.42) + 1) ÷ 2] - 1 }	=	1.71%
5	**WATER COMPANY AVERAGE**						1.85%
6	CGC	CASCADE NATURAL GAS CORPORATION	1.00%	x	{ [((1.90) + 1) ÷ 2] - 1 }	=	0.45%
7	KSE	KEYSPAN CORP.	2.00%	x	{ [((1.42) + 1) ÷ 2] - 1 }	=	0.42%
8	LG	LACLEDE GROUP, INC.	1.00%	x	{ [((1.79) + 1) ÷ 2] - 1 }	=	0.39%
9	NWN	NORTHWEST NATURAL GAS CO.	1.00%	x	{ [((1.65) + 1) ÷ 2] - 1 }	=	0.32%
10	PGL	PEOPLES ENERGY CORPORATION	1.75%	x	{ [((1.73) + 1) ÷ 2] - 1 }	=	0.64%
11	SJI	SOUTH JERSEY INDUSTIES, INC.	2.00%	x	{ [((2.15) + 1) ÷ 2] - 1 }	=	1.15%
12	SWX	SOUTHWEST GAS CORPORATION	3.00%	x	{ [((1.36) + 1) ÷ 2] - 1 }	=	0.54%
13	WGL	WGL HOLDINGS, INC.	0.25%	x	{ [((1.71) + 1) ÷ 2] - 1 }	=	0.09%
16	**NATURAL GAS LDC AVERAGE**						0.50%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/27/2006 (WATER COMPANIES) AND 12/16/2005 (NATURAL GAS LDC's)
COLUMN (C): COLUMN (A) x COLUMN (B)

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	WATER COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	AWR	AMERICAN STATES WATER CO.	2000	0.3281		9.30%		3.05%	12.74	15.12	
2			2001	0.3556		10.10%		3.59%	13.22	15.12	
3			2002	0.3507		9.50%		3.33%	14.05	15.18	
4			2003	-0.1282		5.60%		-0.72%	13.97	15.21	
5			2004	0.1524		6.50%		0.99%	14.98	16.77	
6			GROWTH 2000 - 2004					2.05%	4.00%		2.62%
7			2005	0.1818		7.50%		1.36%		17.10	1.97%
8			2006	0.3724		8.50%		3.17%		17.60	2.44%
9			2008-10	0.5429		12.00%		6.51%	3.50%	20.00	3.59%
10											
11	CWT	CALIFORNIA WATER SERVICE GROUP	2000	0.1603		10.10%		1.62%	12.90	15.15	
12			2001	-0.1915		7.20%		-1.38%	12.95	15.18	
13			2002	0.1040		9.50%		0.99%	13.12	15.18	
14			2003	0.0744		7.90%		0.59%	14.44	16.93	
15			2004	0.2260		9.00%		2.03%	15.65	18.37	
16			GROWTH 2000 - 2004					0.77%	1.00%		4.94%
17			2005	0.2138		9.00%		1.92%		18.50	0.71%
18			2006	0.3235		10.00%		3.24%		19.00	1.70%
19			2008-10	0.4233		11.00%		4.66%	5.00%	23.00	4.60%
20											
21	SWWC	SOUTHWEST WATER COMPANY	2000	0.6500		11.10%		7.22%	3.61	13.33	
22			2001	0.6591		11.40%		7.51%	4.03	13.50	
23			2002	0.6098		9.70%		5.91%	4.49	13.66	
24			2003	0.6383		9.10%		5.81%	5.14	15.40	
25			2004	0.2083		3.60%		0.75%	6.48	19.40	
26			GROWTH 2000 - 2004					5.44%	13.00%		9.84%
27			2005	0.4286		5.00%		2.14%		20.50	5.67%
28			2006	0.5111		6.50%		3.32%		20.50	2.80%
29			2008-10	0.6947		11.00%		7.64%	8.50%	21.50	2.08%
30											
31	WTR	AQUA AMERICA, INC.	2000	0.4043		11.70%		4.73%	3.85	111.82	
32			2001	0.4118		12.40%		5.11%	4.15	113.97	
33			2002	0.4074		12.70%		5.17%	4.36	113.19	
34			2003	0.3860		10.20%		3.94%	5.34	123.45	
35			2004	0.4219		10.70%		4.51%	5.89	127.18	
36			GROWTH 2000 - 2004					4.69%	10.50%		3.27%
37			2005	0.4444		12.00%		5.33%		128.00	0.64%
38			2006	0.4568		12.00%		5.48%		130.00	1.10%
39			2008-10	0.5500		13.00%		7.15%	10.00%	136.00	1.35%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/27/2006
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	CGC	CASCADE NATURAL GAS CORPORATION	2000	0.3094		12.90%		3.99%	10.79	11.05	
2			2001	0.3469		13.30%		4.61%	11.01	11.05	
3			2002	0.1504		10.90%		1.64%	10.34	11.05	
4			2003	-0.1034		8.60%		-0.89%	10.11	11.13	
5			2004	0.1933		11.20%		2.16%	10.52	11.27	
6			GROWTH 2000 - 2004					2.30%	-		0.49%
7			2005	-0.1707		7.50%		-1.28%		11.41	1.24%
8			2006	-0.0105		9.00%		-0.09%		11.40	0.58%
9			2008-10	0.2160		8.50%		1.84%	7.00%	12.00	1.26%
10											
11	KSE	KEYSPAN CORP.	2000	0.1524		10.00%		1.52%	20.65	136.36	
12			2001	-0.0349		8.20%		-0.29%	20.73	139.43	
13			2002	0.3527		13.30%		4.69%	20.67	142.42	
14			2003	0.3206		11.40%		3.65%	22.94	159.66	
15			2004	0.2664		10.20%		2.72%	24.22	160.82	
16			GROWTH 2000 - 2004					2.46%	1.50%		4.21%
17			2005	0.2571		9.50%		2.44%		174.50	8.51%
18			2006	0.2720		9.50%		2.58%		175.00	4.32%
19			2008-10	0.3226		10.50%		3.39%	5.00%	177.00	1.94%
20											
21	LG	LACLEDE GROUP, INC.	2000	0.0219		9.10%		0.20%	14.99	18.88	
22			2001	0.1677		10.50%		1.76%	15.26	18.88	
23			2002	-0.1356		7.80%		-1.06%	15.07	18.96	
24			2003	0.2637		11.60%		3.06%	15.65	19.11	
25			2004	0.2582		10.10%		2.61%	16.96	20.98	
26			GROWTH 2000 - 2004					1.31%	1.50%		2.67%
27			2005	0.2789		11.00%		3.07%		21.00	0.10%
28			2006	0.3050		11.00%		3.36%		21.50	1.23%
29			2008-10	0.3696		8.50%		3.14%	9.50%	21.50	0.49%
30											
31	NWN	NORTHWEST NATURAL GAS CO.	2000	0.3073		10.00%		3.07%	17.93	25.23	
32			2001	0.3351		10.20%		3.42%	18.56	25.23	
33			2002	0.2222		8.50%		1.89%	18.88	25.59	
34			2003	0.2784		9.00%		2.51%	19.52	25.94	
35			2004	0.3011		8.90%		2.68%	20.64	27.55	
36			GROWTH 2000 - 2004					2.71%	3.50%		2.22%
37			2005	0.3767		10.00%		3.77%		27.75	0.73%
38			2006	0.3822		10.50%		4.01%		28.00	0.81%
39			2008-10	0.4036		10.50%		4.24%	4.50%	29.00	1.03%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/16/2005
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PGL	PEOPLES ENERGY CORPORATION	2000	0.2620		12.40%		3.25%	22.02	35.30	
2			2001	0.3544		13.90%		4.93%	22.76	35.40	
3			2002	0.2607		12.30%		3.21%	22.74	35.46	
4			2003	0.2613		12.30%		3.21%	23.11	36.69	
5			2004	0.0092		9.40%		0.09%	23.06	36.69	
6			GROWTH 2000 - 2004					2.94%	2.50%		0.97%
7			2005	0.0354		10.80%		0.38%		38.00	3.57%
8			2006	0.0833		11.00%		0.92%		38.00	1.77%
9			2008-10	0.2516		12.00%		3.02%	2.00%	35.00	-0.94%
10											
11	SJI	SOUTH JERSEY INDUSTIES, INC.	2000	0.3241		14.80%		4.80%	7.25	23.00	
12			2001	0.3565		12.80%		4.56%	7.81	23.72	
13			2002	0.3852		12.50%		4.82%	9.67	24.41	
14			2003	0.4307		11.60%		5.00%	11.26	26.46	
15			2004	0.4810		12.50%		6.01%	12.41	27.76	
16			GROWTH 2000 - 2004					5.04%	11.50%		4.81%
17			2005	0.5401		13.50%		7.29%		28.70	3.39%
18			2006	0.5350		13.00%		6.96%		29.00	2.21%
19			2008-10	0.5000		11.50%		5.75%	9.50%	31.00	2.23%
20											
21	SWX	SOUTHWEST GAS CORPORATION	2000	0.3223		7.20%		2.32%	16.82	31.71	
22			2001	0.2870		6.60%		1.89%	17.27	32.49	
23			2002	0.2931		6.50%		1.91%	17.91	33.29	
24			2003	0.2743		6.10%		1.67%	18.42	34.23	
25			2004	0.5060		8.30%		4.20%	19.18	36.79	
26			GROWTH 2000 - 2004					2.40%	4.00%		3.78%
27			2005	0.4143		7.00%		2.90%		39.00	6.01%
28			2006	0.5030		8.00%		4.02%		39.00	2.96%
29			2008-10	0.6653		10.50%		6.99%	4.00%	41.50	2.44%
30											
31	WGL	WGL HOLDINGS, INC.	2000	0.3073		11.70%		3.59%	15.31	46.47	
32			2001	0.3298		11.70%		3.86%	16.24	48.54	
33			2002	-0.1140		7.20%		-0.82%	15.78	48.56	
34			2003	0.4435		14.00%		6.21%	16.25	48.63	
35			2004	0.3434		11.70%		4.02%	16.95	48.67	
36			GROWTH 2000 - 2004					3.37%	3.00%		1.16%
37			2005	0.3333		11.50%		3.83%		48.70	0.06%
38			2006	0.3649		10.50%		3.83%		48.70	0.03%
39			2008-10	0.4042		11.00%		4.45%	5.00%	48.80	0.05%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/16/2005
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
GROWTH RATE COMPARISON

DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR - 6

WATER COMPANY SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	AWR	7.60%	6.00%	12.00%	1.50%	3.50%	1.50%	1.00%	4.00%	4.21%	-4.83%	0.86%	4.13%
2	CWT	6.81%	9.00%	8.50%	1.50%	5.00%	-6.50%	1.00%	1.00%	2.79%	2.75%	0.67%	4.95%
3	SWWC	7.30%	5.50%	17.00%	9.00%	8.50%	7.00%	10.50%	13.00%	10.07%	-11.99%	7.93%	15.75%
4	WTR	7.71%	9.30%	13.00%	8.00%	10.00%	8.50%	6.50%	10.50%	9.40%	8.02%	7.22%	11.22%
5				12.63%	5.00%	6.75%	2.63%	4.75%	7.13%		-1.51%	4.17%	9.01%
6	AVERAGES	7.35%	7.45%		8.13%			4.83%		6.62%		3.89%	

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	CGC	2.20%	6.00%	3.00%	0.50%	7.00%	1.00%	-	-	3.50%	-3.81%	0.00%	-0.63%
2	KSE	3.42%	3.10%	1.00%	2.00%	5.00%	21.00%	4.00%	1.50%	5.37%	3.82%	0.14%	4.07%
3	LG	3.39%	-	6.00%	1.50%	9.50%	-0.50%	0.50%	1.50%	3.08%	7.36%	0.19%	3.13%
4	NWN	5.32%	5.30%	8.00%	4.50%	4.50%	3.00%	1.00%	3.50%	4.26%	0.96%	1.19%	3.58%
5	PGL	3.64%	4.00%	3.00%	1.50%	2.00%	2.00%	2.00%	2.50%	2.43%	-5.30%	1.94%	1.16%
6	SJI	7.15%	6.00%	8.00%	6.00%	9.50%	10.50%	1.50%	11.50%	7.57%	9.98%	2.95%	14.38%
7	SWX	6.54%	6.00%	10.50%	1.50%	4.00%	1.50%	-	4.00%	4.58%	8.23%	0.00%	3.34%
8	WGL	5.09%	4.00%	5.00%	2.00%	5.00%	2.00%	1.50%	3.00%	3.21%	2.55%	1.19%	2.58%
9				5.56%	2.44%	5.81%	5.06%	1.75%	3.93%		2.97%	0.95%	3.95%
10	AVERAGES	4.59%	4.91%		4.60%			3.58%		4.25%		2.63%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 01/27/2006 (WATER COMPANIES) AND 12/16/2005 (NATURAL GAS LDC's)
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 01/27/2006 (WATER COMPANIES) AND 12/16/2005 (NATURAL GAS LDC's)
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/27/2006 (WATER COMPANIES) AND 12/16/2005 (NATURAL GAS LDC's)

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+	[	ß (A)	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AWR	k	=	4.37%	+	[	0.75	x	(	10.40%	-	4.37%	)]	=	8.89%
2	CWT	k	=	4.37%	+	[	0.75	x	(	10.40%	-	4.37%	)]	=	8.89%
3	SWWC	k	=	4.37%	+	[	0.70	x	(	10.40%	-	4.37%	)]	=	8.59%
4	WTR	k	=	4.37%	+	[	0.80	x	(	10.40%	-	4.37%	)]	=	9.19%
5	**WATER COMPANY AVERAGE**						0.75								8.89%
6	CGC	k	=	4.37%	+	[	0.80	x	(	10.40%	-	4.37%	)]	=	9.19%
7	KSE	k	=	4.37%	+	[	0.85	x	(	10.40%	-	4.37%	)]	=	9.50%
8	LG	k	=	4.37%	+	[	0.80	x	(	10.40%	-	4.37%	)]	=	9.19%
9	NWN	k	=	4.37%	+	[	0.70	x	(	10.40%	-	4.37%	)]	=	8.59%
10	PGL	k	=	4.37%	+	[	0.85	x	(	10.40%	-	4.37%	)]	=	9.50%
11	SJI	k	=	4.37%	+	[	0.65	x	(	10.40%	-	4.37%	)]	=	8.29%
12	SWX	k	=	4.37%	+	[	0.80	x	(	10.40%	-	4.37%	)]	=	9.19%
13	WGL	k	=	4.37%	+	[	0.80	x	(	10.40%	-	4.37%	)]	=	9.19%
14	**NATURAL GAS LDC AVERAGE**						0.78								9.08%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\beta (r_m - r_f)]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 01/13/2006 THROUGH 02/17/2006 WAS USED AS A RISK FREE RATI OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2004 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2004 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	ß (A)	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AWR	k	=	4.37%	+ [	0.75	x	(	12.40%	-	4.37%	)]	=	10.39%
2	CWT	k	=	4.37%	+ [	0.75	x	(	12.40%	-	4.37%	)]	=	10.39%
3	SWWC	k	=	4.37%	+ [	0.70	x	(	12.40%	-	4.37%	)]	=	9.99%
4	WTR	k	=	4.37%	+ [	0.80	x	(	12.40%	-	4.37%	)]	=	10.79%
5	**WATER COMPANY AVERAGE**					0.75								10.39%
6	CGC	k	=	4.37%	+ [	0.80	x	(	12.40%	-	4.37%	)]	=	10.79%
7	KSE	k	=	4.37%	+ [	0.85	x	(	12.40%	-	4.37%	)]	=	11.20%
8	LG	k	=	4.37%	+ [	0.80	x	(	12.40%	-	4.37%	)]	=	10.79%
9	NWN	k	=	4.37%	+ [	0.70	x	(	12.40%	-	4.37%	)]	=	9.99%
10	PGL	k	=	4.37%	+ [	0.85	x	(	12.40%	-	4.37%	)]	=	11.20%
11	SJI	k	=	4.37%	+ [	0.65	x	(	12.40%	-	4.37%	)]	=	9.59%
12	SWX	k	=	4.37%	+ [	0.80	x	(	12.40%	-	4.37%	)]	=	10.79%
13	WGL	k	=	4.37%	+ [	0.80	x	(	12.40%	-	4.37%	)]	=	10.79%
14	**NATURAL GAS LDC AVERAGE**					0.78								10.64%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 01/13/2006 THROUGH 02/17/2006 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2004 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2004 YEARBOOK

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.40%	1.90%	10.01%	6.98%	8.10%	7.49%	8.61%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	8.14%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	7.67%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	6.60%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.20%	4.25%	7.37%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.84%	5.49%	6.88%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	6.70%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	6.61%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	5.58%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	5.86%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.94%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.38%	5.95%	7.59%	8.02%
13	2002	2.40%	1.60%	4.67%	1.17%	1.66%	1.60%	5.38%	7.41%	7.98%
14	2003	1.90%	2.70%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	3.30%	4.20%	4.34%	2.35%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.40%	3.50%	6.16%	4.16%	3.16%	3.17%	4.57%	5.38%	5.78%
17	CURRENT	3.40%	3.50%	7.50%	5.50%	4.50%	4.51%	4.65%	5.69%	6.05%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (F): CURRENT, THE WALL STREET JOURNAL, DATED 02/17/2006
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 02/17/2006
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

BLACK MOUNTAIN SEWER CORPORATION
TEST YEAR ENDED DECEMBER 31, 2004
CAPITAL STRUCTURES OF SAMPLE COMPANIES

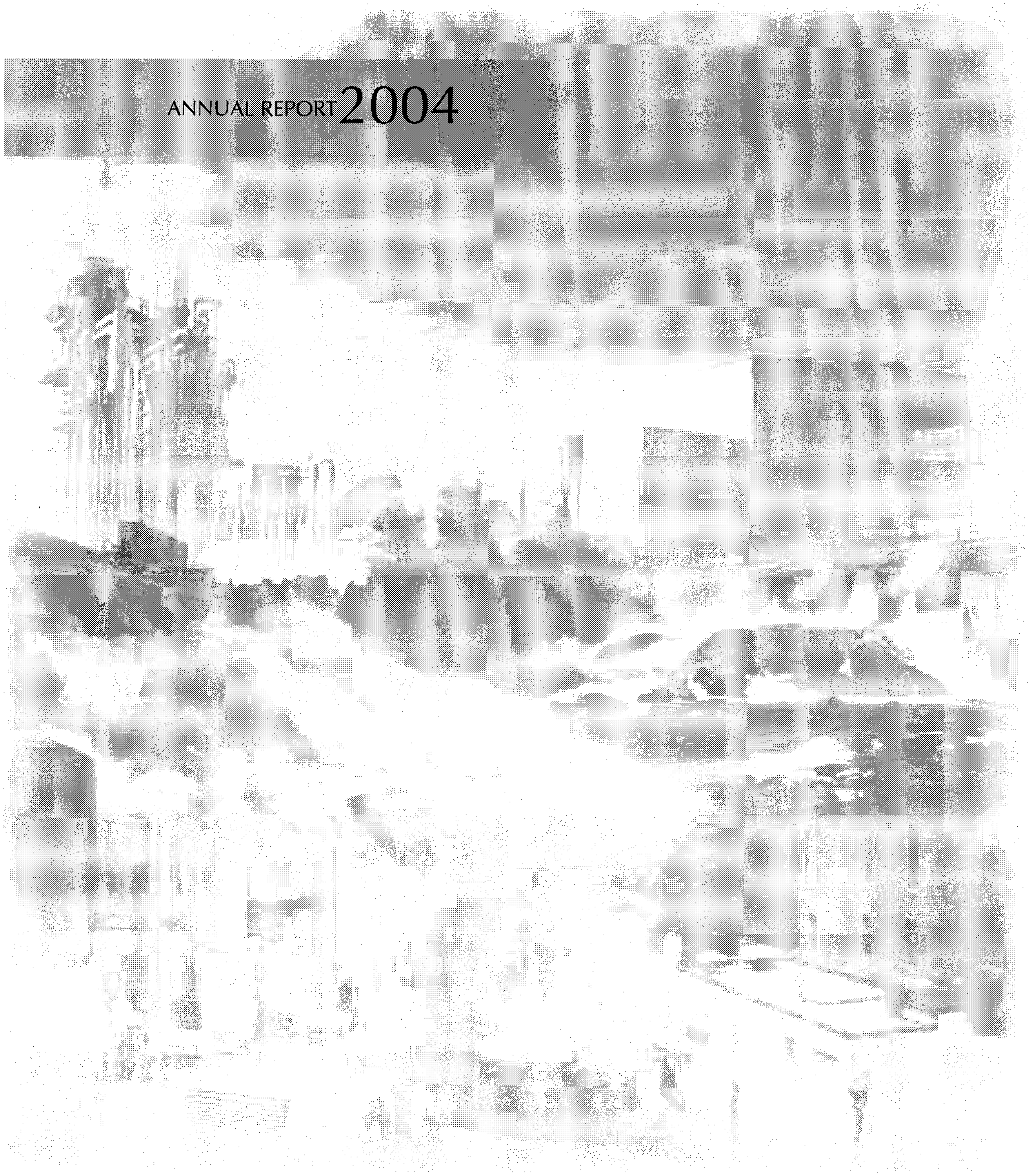
DOCKET NO. SW-02361A-05-0657
SCHEDULE WAR - 9

LINE NO.		AWR	PCT.	CWT	PCT.	SWWC	PCT.	WTR	PCT.	WATER COMPANY AVERAGE	PCT.
1	DEBT	$ 228.9	47.7%	$ 274.8	48.6%	$ 115.8	47.9%	$ 784.5	51.2%	$ 468.0	49.8%
2											
3	PREFERRED STOCK	0.0	0.0%	3.5	0.6%	0.0	0.0%	0.0	0.0%	1.2	0.1%
4											
5	COMMON EQUITY	251.5	52.3%	287.6	50.8%	126.2	52.1%	748.5	48.8%	471.2	50.1%
6											
7	TOTALS	$ 480.4	100%	$ 565.9	100%	$ 242.0	100%	$ 1,532.9	100%	$ 940.4	100%
8											
9											
10		CGC	PCT.	KSE	PCT.	LG	PCT.	NWN	PCT.		
11											
12	DEBT	$ 176.4	59.8%	$ 4,418.7	53.0%	$ 380.3	51.6%	$ 568.5	54.0%		
13											
14	PREFERRED STOCK	0.0	0.0%	19.7	0.2%	1.1	0.1%	0.0	0.0%		
15											
16	COMMON EQUITY	118.5	40.2%	3,894.7	46.7%	355.9	48.3%	484.0	46.0%		
17											
18	TOTALS	$ 294.9	100%	$ 8,333.1	100%	$ 737.3	100%	$ 1,052.5	100%		
19											
20										NATURAL GAS LDC	
21		PGL	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.	AVERAGE	PCT.
22											
23	DEBT	$ 897.4	50.8%	$ 328.9	48.7%	$ 1,181.4	60.8%	$ 590.2	40.1%	$ 1,067.7	52.5%
24											
25	PREFERRED STOCK	0.0	0.0%	1.7	0.3%	100.0	5.1%	28.1	1.9%	18.8	0.9%
26											
27	COMMON EQUITY	870.1	49.2%	344.4	51.0%	663.0	34.1%	853.4	58.0%	948.0	46.6%
28											
29	TOTALS	$ 1,767.5	100%	$ 675.0	100%	$ 1,944.4	100%	$1,471.7	100%	$ 2,034.6	100%

REFERENCE:
2004 SEC 10-K FILINGS

ATTACHMENT A

ANNUAL REPORT 2004



ALGONQUIN POWER Income Fund

STABILITY PERFORMANCE OPPORTUNITY

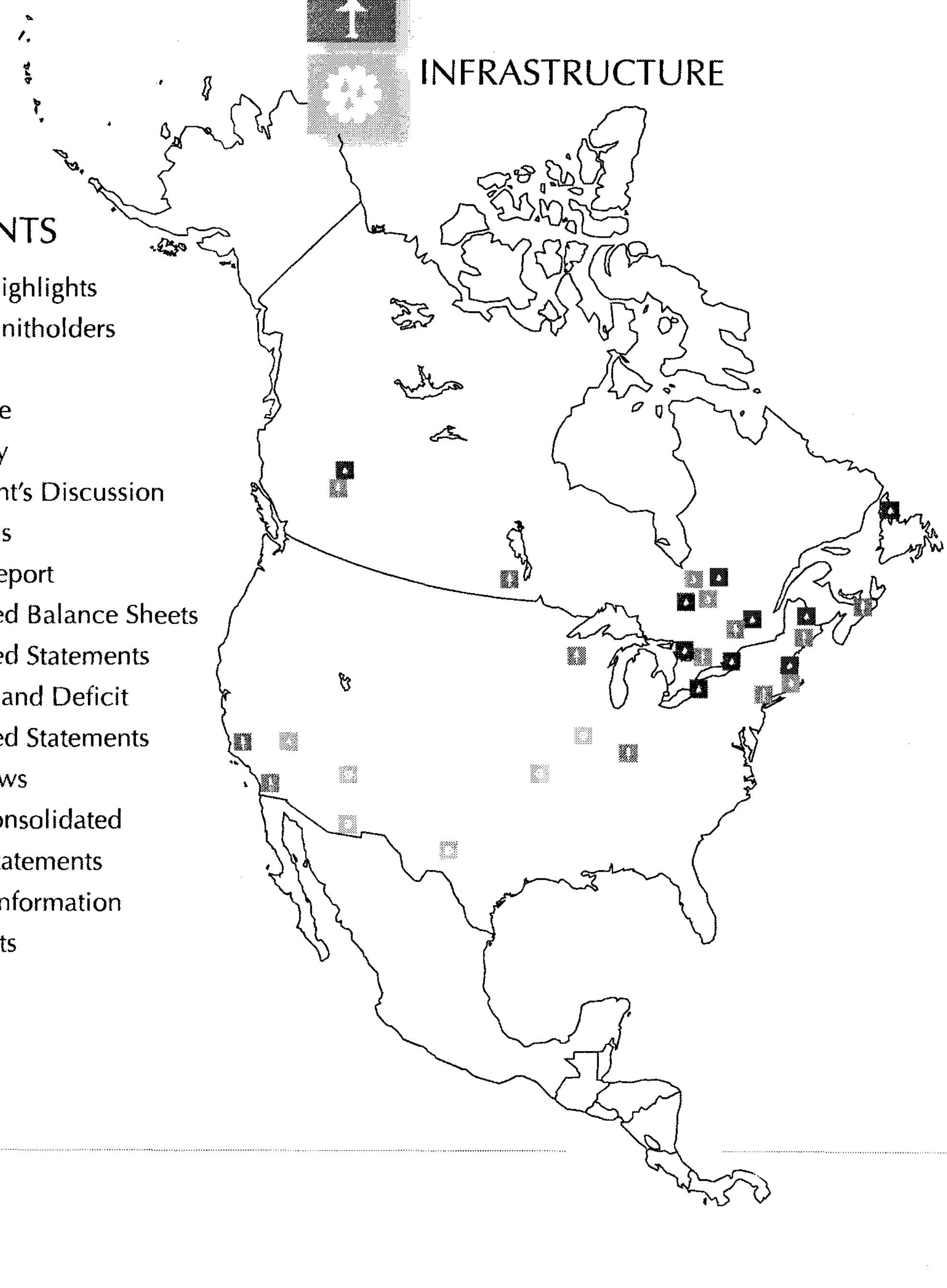
ALGONQUIN POWER
Income Fund

HYDROELECTRIC

COGENERATION

ALTERNATIVE FUELS

INFRASTRUCTURE



CONTENTS

FINANCIAL HIGHLIGHTS

Thousands of Canadian dollars except as noted

Years ended December 31	2004	2003	2002	2001	2000	1999
Energy Sales						
Hydroelectric	$ 43,268	$ 44,413	$ 40,681	$ 36,270	$ 43,996	$ 13,709
Cogeneration	71,846	61,890	23,566	–	–	–
Alternative fuels	7,867	6,423	4,994	1,020	–	–
Total energy sales	$ 122,981	$ 112,726	$ 69,241	$ 37,290	$ 43,996	$ 13,709
Waste disposal	14,086	14,650	10,697	–	–	–
Water reclamation/distribution	23,456	20,237	7,974	2,522	–	–
Interest, dividend and other income	6,681	6,608	6,851	5,157	2,697	5,896
Total revenue	$ 167,204	$ 154,221	$ 94,763	$ 44,969	$ 46,693	$ 19,605
Operating Profit (includes interest, dividend and other income)						
Hydroelectric	$ 26,383	$ 29,045	$ 26,985	$ 24,835	$ 33,351	$ 13,051
Cogeneration	25,273	23,773	15,069	1,166	–	–
Alternative fuels	8,181	9,328	7,292	719	–	–
Infrastructure	12,616	11,117	4,678	1,199	–	–
Other	739	278	851	2,530	1,063	2,016
Total operating profit	$ 73,192	$ 73,541	$ 54,875	$ 30,449	$ 34,414	$ 15,067
Net earnings	22,802	44,507	16,150	6,864	13,364	7,209
Per trust unit	0.33	0.66	0.28	0.17	0.54	0.37
Distributions to unitholders	63,370	62,402	55,192	37,302	24,755	18,467
Per trust unit	0.92	0.92	0.92	0.92	0.97	0.90
Cash available for distribution	59,887	58,368	44,742	28,813	19,235	13,779
Per trust unit	0.87	0.86	0.77	0.73	0.78	0.70
Balance Sheet Data						
Cash and cash equivalents	34,197	21,238	24,838	31,713	9,580	9,602
Working capital	17,242	9,337	15,376	19,011	2,024	(768)
Capital and intangible assets, and long-term investments	742,994	751,904	674,495	467,312	310,056	305,084
Total assets	823,899	808,624	723,038	512,384	328,502	325,988
Long-term liabilities and revolving credit facility (includes current portion)	206,017	166,713	86,099	50,665	73,244	83,985
Unitholders' equity	495,271	519,876	537,771	411,613	219,559	205,221
Number of units outstanding as of December 31	69,691,592	67,887,612	67,887,612	50,875,772	27,020,472	24,020,472

REPORT TO UNITHOLDERS

THE YEAR 2004 WAS ONE OF ACHIEVEMENT AND MEASURABLE PROGRESS FOR THE FUTURE.

A solid diversification strategy and improvements in operational performance enabled the Fund to provide predictable cash distributions to unitholders.

2004 ACHIEVEMENTS:

- **Algonquin Power Income Fund distributed $0.92 per trust unit during 2004, consistent with 2003**
- **Revenue increased to $160.5 million from $147.6 million**
- **Cash available for distribution increased to $59.9 million from $58.4 million**
- **Cash available for distribution per trust unit increased to $0.87 from $0.86.**

The Fund has laid the groundwork for a diversified portfolio of power generation and infrastructure assets designed to contribute stable and increasing cash flows in this decade and beyond.

From this strong foundation of high quality assets distributed among four operating divisions, management anticipates that future growth- both organic and acquisitive- will result in further improved operating margins and distributions to unitholders.

The Fund's diversification strategy - established in 2001, accelerated in 2002, solidified in 2003 and 2004 – delivered strong overall performance this year. The Fund has generated continuously increasing cash available for distribution. During 2004, the Fund generated $59.9 million in cash available for distribution compared to $58.4 million in 2003. Cash available for distribution per trust unit in 2004 was $0.87 compared to $0.86 in 2003.

The continuing maturation of the diversification strategy, management's focus on operational performance improvement and relatively strong hydrology underpinned results this year.

The benefits of the maturation process are evidenced in the overall balance of the Fund's portfolio. The Fund's assets are deployed in hydroelectric generation (37%), natural gas cogeneration (19%), alternative fuels or biomass-fired generating assets (18%) and infrastructure including water provision and recycling assets (21%) with the balance as administrative assets.

Operating profits (includes interest, dividend and other income) are also well-balanced among hydroelectric (37%), natural gas cogeneration (35%), alternative fuels or biomass-fired generating assets (11%) and infrastructure (17%).

Reduced benefits from the prior year in unrealized foreign exchange gains and a reversal in future income tax from a future tax recovery to a tax expense adversely impacted net earnings which decreased from $44.5 million to $22.8 million. Net earnings per trust unit also decreased to $0.33 from $0.66.

Your Fund continues its policy to hedge a significant portion of its foreign currency exposure. The Algonquin Power Income Fund is positioned well to provide stable and predictable cash distributions to unitholders.

PROGRESS FOR THE FUTURE

While improving overall results during the year, the Fund simultaneously completed strategic initiatives aimed at providing stable and predictable cash distributions to unitholders for the future.

In June, the Fund completed the take-over of certain of the convertible debentures of KMS Power Income Fund not previously owned by Algonquin Power Trust. The completion of this take-over bid created the opportunity for the Fund to streamline further its operations with KMS and develop increased efficiencies.

In July, the Fund completed an offering of 85,000 convertible unsecured subordinated debentures for gross proceeds of $85 million. Net proceeds from the offering were used to re-pay debt and for general corporate purposes.

In October, the Fund acquired an interest in 12 landfill gas-powered generating stations capable of producing 36 megawatts of installed capacity for a consideration of $11.4 million. Also, the Fund provided debt financing in the amount of $8.0 million to Across America LFG LLC, a majority-owned subsidiary of a Fortune 50 company. Across America owns and manages the landfill gas collection systems that provide landfill gas to the 12 generating stations. The majority of these acquired facilities are located in the California basin. The increased demand for electricity combined with open growth landfill sites is anticipated to generate growth in cash generation for the Fund.

In November, the Fund committed to lend $69 million as subordinated debt to AirSource Power Fund I LP. AirSource is utilizing the Fund's monies along with equity raised ($65 million) and other senior and subordinated debt to build a $210 million wind power project in southern Manitoba. The project is the Province's first wind farm and will feature 63 wind turbine generators capable of generating 99 MW. The wind farm is expected to be one of the largest in North America.

OUTLOOK

The Fund continues to focus on its commitment to improve the performance of existing assets and to identify and secure accretive acquisitions to build the stability of distributions to unitholders, balance risk and enhance growth opportunities.

Cash generated by the Fund's four divisions is expected to continue growing, subject to continuation of average hydrologic conditions and the continuing benefits of portfolio diversification.

As evidenced by the Fund's investment this year in landfill gas-powered generation and the wind farm in Manitoba, management continues to seek complementary, accretive acquisitions that offer highly predictable cash flows.

Your Fund continues to benefit from access to capital through markets and from established banking credit facilities. Your continuing support has been fundamental to our ability to maintain stable cash flows and to grow the portfolio. We will continue our progress in the coming year by focusing on stable distributions and operational performance and by capitalizing on opportunities and favourable market factors within targeted segments of the North American power generation industry.

Ken Moore
Chairman

Trustees: (L to R) Christopher Ball, George Steeves, and Ken Moore.

STABILITY

SUSTAINABLE CASH DISTRIBUTIONS

The Fund launched its diversification strategy in 2001 to create a balanced asset portfolio. The objective was to diversify across technologies, geography and end-use markets to minimize risk and provide stable distributions to unitholders.

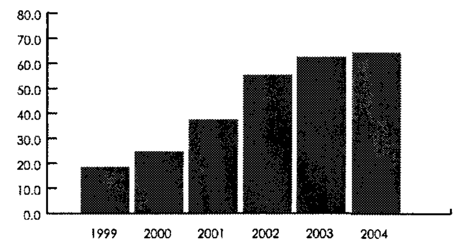
ASSET DEPLOYMENT

Three years ago, the Fund's assets were exclusively 'run-of-the-river' hydroelectric generating stations in selected geographic regions of Canada and the United States. Today, the Fund's assets are strategically deployed in hydroelectric generation (37%), natural gas cogeneration (19%), alternative fuels or biomass-fired generation (18%), and infrastructure, including potable water distribution and water reclamation services (21%). The balance is classified as administrative assets (5%).

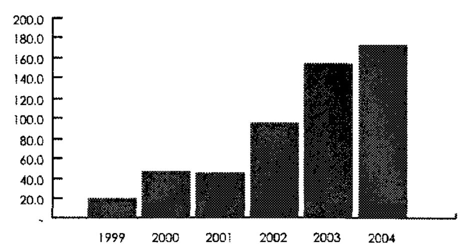
POWER PURCHASE AGREEMENTS

On a weighted average basis, power purchase agreements in place have an average lifespan of 15 years, contributing to strong and stable cash flows in hydroelectric generation, natural gas cogeneration and in the production of electricity from alternative fuels.

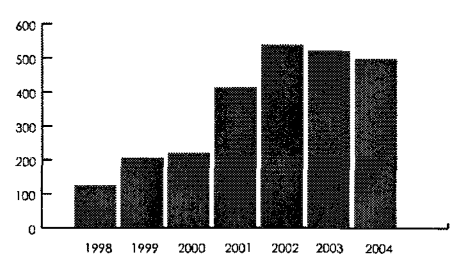
Annual distributions
$ millions



Annual revenues
$ millions

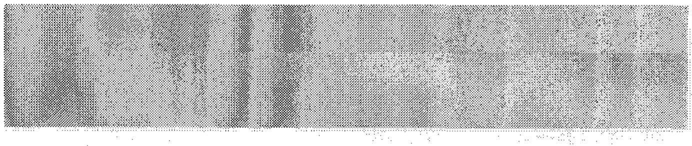


Unitholders' equity
$ millions

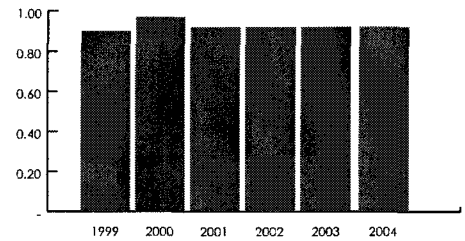


REVENUES

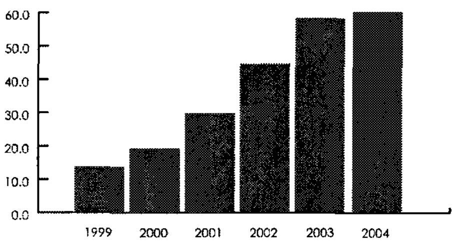
Total revenue generated in 2004 is distributed among hydroelectric (27%), cogeneration (45%), alternative fuels (14%) and infrastructure (14%). During 2004, revenues were 94% of target across the Fund's four divisions.



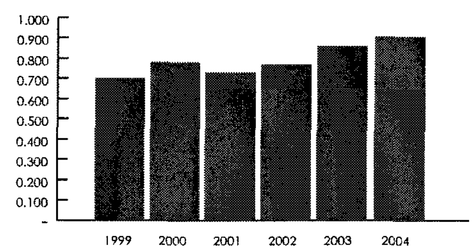
Distribution to unitholders
$ per trust unit



Cash available for distribution
$ millions



Cash available for distribution
$ per trust unit



OPERATING PROFIT

Operating profit (includes interest, dividend and other income) before depreciation is distributed among hydroelectric (37%), cogeneration (35%), alternative fuels (11%), and infrastructure (17%). Further, operating profit is distributed across geographic and regulatory markets in Canada (Ontario 24%, Quebec and Atlantic Canada 21%, Western Canada 6%) as well as the United States (New England 20%, Arizona 17%, California 9%, New York 2% and other regions 1%). During 2004, operating profit was 94% of targeted performance across the four divisions.

CASH AVAILABLE FOR DISTRIBUTION

The Fund's diversified asset portfolio has generated strong cash available for distribution. During 2004, the Fund generated $59.9 million of cash available for distribution compared to $58.4 million in 2003. Cash available for distribution per trust unit in 2004 was $0.87 compared to $0.86 in 2003.

STABLE RATINGS

Financial leverage continues to be low with a debt to total capital ratio of 29%. The Fund retained its Standard & Poor's SR-2 (Very High) stability rating for a fifth consecutive year and an A- bank credit rating for the third consecutive year.

The strategic diversification in asset allocation has created greater balance in the Fund, providing increased stability in cash distributions. The move toward a more stable structure is evident through revenue and operating profit distributions in the Fund, along with a solid weighted average life-span of power purchase agreements. The Fund has improved overall risk exposure inherent in natural resource-based power generation, providing unitholders with sustainable cash distributions during 2004 and projected to continue through 2005.

PERFORMANCE

STRENGTHENING OPERATIONS BY INVESTING IN EQUIPMENT AND PEOPLE

The Algonquin Power Income Fund was created in 1997 to provide unitholders with stable, predictable income by capitalizing on the inherent advantages of independent power production. These advantages include low operating costs, long-term asset life, proven low-risk technology, reduced regulatory burden compared with large publicly-owned utilities and stipulated rate revenues from long-term power purchase agreements.

The Fund's experienced team of industry professionals is organized in a divisional management structure to focus on operational performance, synergies and economies of scale in each of the Fund's four divisions.

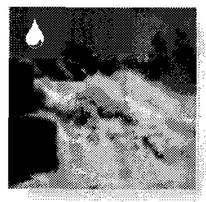
During 2004, the Fund's Manager continued to invest strategically to generate operational performance improvements.

Approximately $16 million was invested in the Infrastructure Division, including expansions of the Gold Canyon and Litchfield Park Services Company water treatment facilities in Arizona. The first phase of the Gold Canyon plant expansion is expected to come on stream in the first quarter, 2005. The expansion of Litchfield Park's Palm Valley water treatment plant will double the capacity of this operation. Both expansions are scheduled for full completion in 2005.

The Fund's Manager also continues to invest in people. Performance management training for key managers was completed during the year. A new health and safety program, launched in 2003, was continued and strengthened.

Our management team and these strategic investments in equipment and people yielded effective operational performances in the Fund's four divisions during the year.

HYDROELECTRIC DIVISION



The Fund owns or has interests in 47 hydroelectric generating facilities in Ontario (5), Quebec (12), Newfoundland (1), Alberta (1), New York State (12), New Hampshire (13), New Jersey (1) and Vermont (2) with total generating capacity of approximately 140MW. The Division's gross revenue is derived from the combination of energy production and power purchase rates.

Hydroelectric assets generated 101% of targeted revenue during 2004 and the Division's operating profit was 100% of forecast.

Hydrologic conditions approached long-term averages throughout the year in regions of North America where the Fund operates hydroelectric generating stations. Together, the Long Sault Rapids, Cote Ste.-Catherine and Dickson Dam facilities account for more than 40% of the total gross revenues for the Division. Long Sault generated 104% of targeted production during the year; Cote Ste-Catherine and Dickson Dam each generated 97% of target.

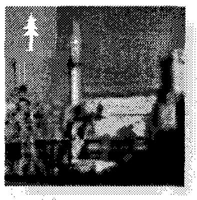
(L to R) The Management Group: Peter Kampian, Chief Financial Officer, Ian Robertson, Executive Director, Business Development, Chris Jarratt, Executive Director, Operations and David Kerr, Executive Director, Safety and Environmental Compliance. Not shown: *John Huxley, Executive Director,* Administration.

COGENERATION DIVISION

This Division is comprised of three natural gas-fired generating stations representing a total of approximately 110MW of installed capacity in Connecticut, California, and New Jersey. In addition, The Fund has investments in two natural gas-fired generating facilities with installed capacity of approximately 138MW across Ontario. Revenue from these operations is generated through the sale of thermal energy and electricity.

Cogeneration assets produced 100% of targeted revenue during the year while the Division's operating profit was 99 % of forecast.

ALTERNATIVE FUELS DIVISION



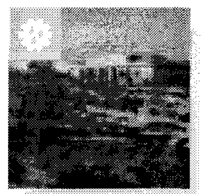
The Alternative Fuels Division consists of a 500-tonne/day energy-from-waste facility in Ontario and investment interests in approximately 70MW of production in Alberta, Quebec and Nova Scotia. The Division acquired an interest in 12 landfill gas-powered generating stations in the United States, representing approximately 36MW of installed capacity during 2004.

The Division also made a commitment to invest approximately $69 million in a wind energy project in Southern Manitoba.

Revenue is generated primarily *from the sale of electricity, fees* at the energy-from-waste facility, and interest and investment income from the other assets.

Alternative Fuels Division assets generated 90% of targeted revenue and the Division's operating profit was 90% of forecast.

INFRASTRUCTURE DIVISION



This Division includes six regulated water reclamation and distribution utilities in Arizona and Texas. Revenue is generated from the sale of water and the treatment of wastewater.

The Division's assets generated 101% of targeted revenue and the Division's operating profit was 93% of forecast.

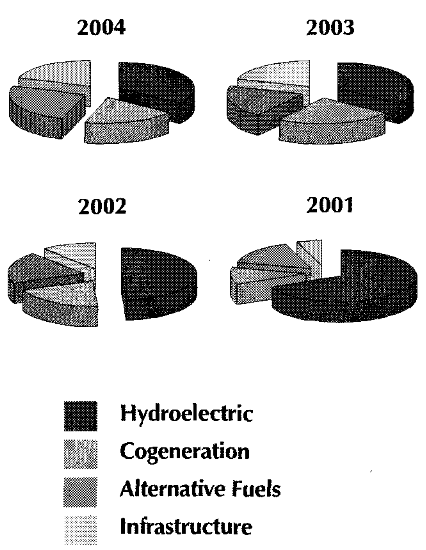
The investment in equipment and people in 2004 has contributed to the overall performance of the four divisions. Growth in the business precipitated this requirement and has contributed to the opportunities and advantages inherent in today's power production market. The Fund will continue to focus on performance enhancing opportunities in the future.

OPPORTUNITY

NORMAL HYDROLOGIC CONDITIONS, CONTINUED GROWTH & EMERGING MARKETS

The Fund expects to enjoy the benefits of the diversification strategy that was initiated in 2001 and continued through 2004. The benefits of the diversification strategy include minimizing risk and enhancing stability of distributions provided to unitholders.

In 2004, the Fund's assets were deployed in hydroelectricity (37%), natural gas cogeneration (19%), alternative fuels (18%) and infrastructure (21%) with the balance as administrative assets (5%). The following chart shows the progression of the diversification strategy employed by the Fund since 2001.



While management continues to seek accretive acquisitions in each operating division, the Fund expects the strongest growth opportunities to be realized within the Alternative Fuels and Infrastructure Divisions. As a result, management expects the Fund to evolve into a balanced portfolio of asset types that will further enhance stability of distributable cash to unitholders.

Management will continue to focus on improving the performance of the existing assets owned by the Fund. The Production Recovery Action Plan developed and completed for the Peel Energy-from-Waste facility during 2004 will be continuously refined and improved. Several of the initiatives have been implemented including technical improvements and key personnel changes. The positive results of these initiatives are expected to be realized throughout the balance of 2005.

HYDROLOGIC CONDITIONS

Widespread hydrologic conditions are a potential risk that can adversely affect the performance of the Fund's run-of-river hydroelectric assets. The hydrologic conditions in areas in which the Fund owns hydroelectric facilities returned closer to normal in 2003 and continued throughout most of 2004. Management expects these normal hydrologic conditions to continue in 2005, with higher levels of certainty associated with hydrologic conditions in the first quarter of 2005.

In 2005, January and February production-based revenue totalled 101% of target, demonstrating a strong start to the first quarter for the Hydroelectric Division. This indicates that the smaller contributing assets are performing well and compensating for the lower-than-target production and revenues at the larger Long Sault Rapids and Côte Ste-Catherine facilities during the first two months of 2005. Favourable power purchase rates at both the New York and New England market sites are also assisting in achieving target revenue performance of the Division. First quarter production in 2005 is expected to be at target, depending on freshet conditions in the various regions. Projected continued favourable market power purchase rates are expected to result in revenue above targets. Snow pack in many of the regions melted in mid-February, resulting in a 'spike' in production for the Division. However, the snow pack appeared to have been replenished by late February snowfalls that should produce a normal freshet, assuming average temperatures and precipitation conditions. Any deviation from target production levels in the quarter will likely be a result of lower than normal levels of precipitation during the coming months or colder than normal temperatures resulting in snow accumulation rather than increased river flows. However, no such deviation is evident in the current trend.

GROWTH OPPORTUNITY: INFRASTRUCTURE DIVISION

The Fund currently enjoys the benefit of a significant investment in infrastructure utility assets including water systems and water treatment assets located in the southern United States. These infrastructure assets are ideal for the Fund as they represent an asset class which produces stable, predictable and infinitely long-lived cash flows. In addition, due to the high population growth occurring within the regions served by the Fund's utilities, significant "organic" growth in operating earnings is expected by management. The Fund's infrastructure assets experienced organic customer growth of 8.8% in 2004, and management expects this growth rate to continue in 2005.

While the Fund's infrastructure utilities are generally located in areas experiencing high population growth, new residential and commercial development is also occurring in areas contiguous to and near utilities currently owned by the Fund. Management is anticipating an opportunity to grow the Infrastructure Division through expansion of existing utility boundaries.

During the first quarter of 2005, management completed the acquisition of eight facilities serving approximately 7,000 customers located in Illinois, Missouri and Texas.

Management will continue to seek accretive acquisitions that will further enlarge and enhance the Infrastructure Division. Specifically, acquisitions will be sought in areas that are experiencing high population growth to support stable and growing distributions to unitholders.

GROWTH OPPORTUNITY: ALTERNATIVE FUELS DIVISION

The Fund made two significant acquisitions in the Alternative Fuels Division in 2004 which are expected to make an accretive contribution to distributable cash in the future. Management expects to continue pursuing accretive acquisitions in 2005.

In 2004, the Fund committed to a $69 million investment in a 99 megawatt wind energy project located in the town of St. Leon, 150 kilometers south of Winnipeg, Manitoba. The St. Leon project is being developed by AirSource Power Fund I LP, and is expected to be commissioned at the end of 2005, or early in 2006. With the deployment of the investment in the St. Leon Wind Energy Project, the Fund expects the Alternative Fuels Division to grow significantly in 2005. The St. Leon Wind Energy Project investment was structured in a manner which is expected to result in extremely stable and sustainable cash flows to the Fund. In addition, management expects the Fund to participate in a further opportunity to increase the investment in the St. Leon wind power facility upon the successful completion and commissioning of the project.

The Fund also made an investment in 12 operating energy from landfill gas projects located in the United States in 2004. While these acquisitions resulted in immediate contributions to distributable cash to unitholders, there exists significant opportunity to realize additional revenues from these assets through a variety of revenue enhancements. Management expects to realize several of these revenue enhancement opportunities in 2005 and beyond.

EMERGING MARKET: WIND POWER

Worldwide, wind energy is the fastest growing source of electricity and the high growth rate of this sector is expected be prevalent in Canada in the future. The current installed capacity of wind power in Canada is 444 megawatts and this is expected to grow to 5,600 megawatts by the end of 2012. The Fund's investment in the St. Leon Wind Energy Project represents an important entry into this emerging energy sector.

Wind energy projects have no fuel costs, low operating costs, are characterized as renewable energy and electricity produced is usually sold pursuant to long-term power purchase agreements. Accordingly, management believes that wind energy projects are ideal acquisition opportunities for the Fund as wind projects typically produce long-term and stable cash flows. Management will be actively pursuing accretive acquisition opportunities in wind energy projects that will further expand the Alternative Fuels Division.

OTHER EMERGING OPPORTUNITIES IN CANADA

Several Canadian provinces are taking initiatives to increase the level of non-utility energy generation. Requests for Proposal have been initiated recently in Ontario, Quebec, and British Columbia. The Fund will pursue some of these opportunities to continue strengthening its portfolio and enhance unitholder value. It is expected that the majority of opportunities will exist in cogeneration, wind power and alternative fuels.

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 8, 2005.

All figures in thousands of Canadian dollars, except per unit values.

For the fourth quarter ended December 31, 2004, Algonquin Power Income Fund (the "Fund") reported revenue (excluding interest income) of $40.7 million compared to $39.7 million for the same period of 2003. During the fourth quarter of 2004, the Fund posted a net loss of $0.1 million compared to net income in the fourth quarter of 2003 of $6.4 million. On a per trust unit basis, this equated to break even results for the fourth quarter of 2004 compared to net income per trust unit of $0.10 in the fourth quarter of 2003.

For the fourth quarter of 2004, the Fund generated $0.18 per trust unit of cash available for distribution, compared to $0.26 for the same period in 2003. The Fund maintained distributions during the quarter at $0.23 per trust unit.

For the year ended December 31, 2004, the Fund reported revenue of $160.5 million compared to $147.6 million for 2003. Net earnings decreased to $22.8 million compared to $44.5 million for 2003. Net earnings per trust unit decreased to $0.33 from $0.66 in 2003.

The Fund generated $0.87 per trust unit of cash available for distribution during 2004, compared to $0.86 for 2003.

The Fund maintained year-to-date distributions per trust unit at $0.92 for both 2004 and 2003.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended December 31		Year Ended December 31		
	2004	**2003**	**2004**	**2003**	**2002**
Revenue	$ 40,726	$ 39,686	$160,523	$147,613	$ 87,912
Net earnings (loss)	(86)	6,419	22,802	44,507	16,150
Distribution to Unitholders	16,015	15,600	63,370	62,402	55,192
Cash Available for Distribution	12,685	17,400	59,887	58,368	44,742
Per Unit					
Net earnings	0.00	0.10	0.33	0.66	0.28
Distribution to Unitholders	0.23	0.23	0.92	0.92	0.92
Cash Available for Distribution	0.18	0.26	0.87	0.86	0.77
Total Assets			823,899	808,624	723,038
Total Long Term Liabilities			214,045	174,739	92,549

For the fourth quarter of 2004, revenue increased marginally over the same period in 2003 due to the offsetting effects of improved revenue from the Alternative Fuels and Infrastructure Divisions, compared to the expected revenue decline in the Hydroelectric Division resulting from lower re-negotiated power rates in New Hampshire. The Infrastructure Division demonstrated solid performance with increasing revenues from continuing customer growth. Within the Alternative Fuels Division, an additional $2.2 million in revenue resulting from the acquisition of the landfill gas (LFG) Facilities on September 30, 2004 was partially offset by lower waste disposal fees and energy revenue from the Peel Energy-from-Waste facility. The Cogeneration Division was able to offset lower revenue from the Sanger facility against increased sales of electrical and thermal energy at the Windsor Locks facility. In the Hydroelectric Division, electrical energy production was at 87% per cent of long-term averages during the fourth quarter of 2004, which was disappointing particularly when compared to the exceptional hydrology experienced in the fourth quarter of 2003 during which energy production exceeded 114% of long-term averages.

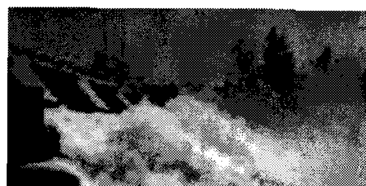
Net income during the fourth quarter of 2004 declined from that reported in the same period in 2003 due primarily to the decrease in earnings from the Hydroelectric Division caused by significantly weaker hydrologic conditions. The Alternative Fuels Division generated lower earnings during the quarter than the same period in the prior year due to higher repair and maintenance costs at the Peel Energy-from-Waste facility which were not totally offset by the addition of the LFG Facilities. The Cogeneration Division posted higher earnings during the quarter as a result of higher revenue generated. Earnings during the quarter in the Infrastructure Division strengthened significantly compared with the same period in 2003 due to continuing customer growth. During the fourth quarter of 2004, the Fund realized a non-cash expense from the write-off of assets related to the Joliet facility following determination by the Fund that it was unlikely to realize on the long-term value of this asset. In addition, the Fund recognized an unrealized foreign exchange loss during the fourth quarter of 2004 as compared to a foreign exchange gain during the same period in 2003.

For the year ended December 31, 2004, the Fund posted increased revenue compared to revenue in 2003. Increased electrical and thermal energy revenue at the Cogeneration Division's Windsor Locks facility and higher revenue from the Infrastructure Division's Litchfield Park facility, both acquired during the first quarter of 2003, were the main contributors to the higher revenue posted by the Fund during 2004. The Alternative Fuels Division posted higher revenue as a result of the acquisition of the LFG Facilities at the end of the third quarter. These increases were offset by the anticipated decline in revenue in the Hydroelectric Division resulting from lower power rates following renegotiation of the power purchase agreements in return for a lump sum payment in mid-2003.

Net earnings for the year ended December 31, 2004 declined compared to net earnings reported in 2003 as a result of a reversal in future income taxes from a recovery in 2003 to an expense in 2004, a reduction in foreign exchange gains compared to 2003 and lower operating profit in the Hydroelectric Division. This decline was partially offset by note prepayment fees and higher profits experienced in the Cogeneration and Infrastructure Divisions.

The information in this Management's Discussion and Analysis is supplemental to and should be read in conjunction with the Fund's audited consolidated financial statements for the year ended December 31, 2004. The Fund's financial statements are prepared in accordance with accounting principles generally accepted in Canada. The Fund's reporting currency is the Canadian dollar.

The term "cash available for distribution" is used throughout this Management's Discussion and Analysis to provide an understanding of the cash generated and available for distribution to unitholders. Cash available for distribution is not a recognized measure under accounting principles generally accepted in Canada. The Fund's method of calculating cash available for distribution may differ from methods used by other companies and accordingly may not be comparable to similar measures presented by other companies. A calculation of cash available for distribution can be found in this Management's Discussion and Analyis.



SIGNIFICANT TRANSACTIONS

THE FUND COMPLETED FOUR SIGNIFICANT TRANSACTIONS DURING 2004:

1. FINANCING FOR AIRSOURCE POWER FUND I LP

During the fourth quarter, the Fund provided a commitment for a total of $69.2 million in subordinated debt to AirSource Power Fund I LP ("AirSource") and subsidiary entities. AirSource is undertaking the completion of a 99 MW wind-powered generating facility near St. Leon, Manitoba (150 km southwest of Winnipeg) which will sell its output to Manitoba Hydro pursuant to a 25-year power sale agreement. The transaction represents the Fund's entry into the fast growing wind power generation industry which, similar to hydroelectric energy, generates electrical energy from a renewable natural resource. The debt investment by the Fund ranks in priority to the $65 million equity flow-through tax assisted financing completed by AirSource in November 2004.

The subordinated debt commitment to AirSource will earn interest at the annual rate of 11.19% prior to project completion. This yield will be reduced to 10.74% following project commissioning which is planned to occur by the end of 2005. At the end of 2004, the Fund had advanced a total of $5.5 million to AirSource and recognized a commitment fee of $0.5 million as deferred revenue with respect to the investment.

2. INTEREST IN LANDFILL GAS ("LFG") FACILITIES

At the end of the third quarter, the Fund acquired interests in 12 landfill gas-powered generating stations representing approximately 36MW of installed capacity. The purchase price for the LFG Facilities was $11.7 million (US $9.3 million). The majority of the LFG Facilities were commissioned in the late 1990s with the electricity produced being sold to a number of large utilities pursuant to long-term power purchase agreements with an average termination date of 2011. Over two thirds of the installed capacity of the LFG Facilities is located at large open landfills which are continuing to accept waste including three regional landfills in the southern California basin which are permitted for operation for at least 25 years. Substantial opportunity exists for expansion of the generating capacity of these facilities as gas production continues to increase.

In addition to the purchase of the LFG Facilities, the Fund has provided debt financing in the amount of $8.0 million (US$6.7 million) to Across America LFG LLC, a majority-owned subsidiary of a Fortune 50 company. Across America LFG LLC, through its subsidiaries, owns and manages the landfill gas collection systems which provide landfill gas to the LFG Facilities.

3. CONVERTIBLE DEBENTURE OFFERING

In the third quarter, the Fund completed an offering of $85 million of convertible unsecured debentures. The debentures are due July 31, 2011 and bear interest at 6.65% per annum, payable semi-annually in arrears. The debentures are to be repaid, at the option of the Fund, in cash or trust units and are convertible at any time prior to maturity at the option of the holder into trust units of the Fund at a conversion price of $10.65 per trust unit. The debentures may not be redeemed by the Fund prior to July 31, 2007. Net proceeds from the debenture offering were used to repay the acquisition line of credit and to fund working capital. Given the nominal equity portion, the debentures are recorded as debt on the Fund's financial statements.

4. ACQUISITION OF OUTSTANDING DEBENTURES OF KMS POWER INCOME FUND

In the second quarter, Algonquin Power Trust (APT), a trust of which the Fund is the sole beneficiary, acquired all of the outstanding 10% convertible debentures of KMS Power Income Fund ("KMS"), which were not beneficially owned by the Fund, by way of a take-over bid with payment provided in the form of the Fund's trust units.

These four transactions have combined to strengthen the Fund's asset base, and diversify the Fund's portfolio of power generation assets and investments.

OPERATING RESULTS BY DIVISION

HYDROELECTRIC

All figures in thousands of Canadian dollars except as noted

	Three Months Ended December 31 2004	Three Months Ended December 31 2003	Year Ended December 31 2004	Year Ended December 31 2003	Forecast Production 2005
Performance (MW-hrs sold)					
Quebec Region	64,039	79,789	288,161	265,452	289,018
Ontario Region	28,319	41,094	137,310	131,721	146,639
New England Region	16,991	26,805	72,862	84,400	72,519
New York Region	20,288	28,501	79,891	90,304	75,746
Western Region	12,506	10,805	63,931	59,947	67,248
Total	142,143	186,994	642,155	631,824	651,170
Revenues					
Energy Sales	$ 10,282	$ 11,340	$ 43,268	$ 44,413	
Expenses					
Operating Expenses	$ (4,673)	$ (3,613)	$(17,422)	$(15,862)	
Interest and Other Income	$ 166	$ 196	$ 557	$ 494	
Division Operating Profit (Includes Other Income)	$ 5,775	$ 7,923	$ 26,403	$ 29,045	

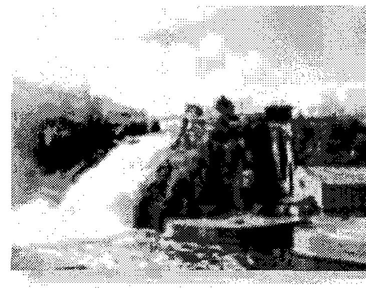
During the fourth quarter of 2004, revenue from the Hydroelectric Division was $10.3 million compared to $11.3 million for the same period in 2003. Electrical energy production was 87% of long-term averages during the fourth quarter of 2004. This is a decreased performance when compared to the exceptional hydrologic conditions experienced in the fourth quarter of 2003 during which energy production was 114% of long-term averages. Although the quantity of electrical energy produced quarter-over-quarter declined 24% to 142,143 MW-hrs, primarily due to less favourable hydrology, revenue declined only 8.8% to $10.3 million due to escalations in the power purchase contracts and finalization of negotiations with Ontario Electricity Financial Corporation regarding the revised power rate escalation formula for the Long Sault Rapids facility.

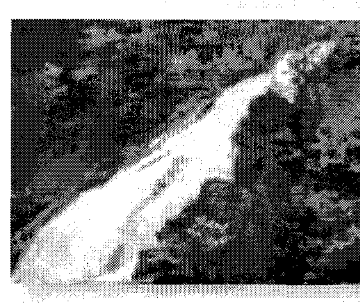
For the full year 2004, revenue from the Hydroelectric Division was $43.3 million compared to $44.4 million in 2003. Revenue for the year decreased despite improved energy production due primarily to the reduction in electricity rates paid in New Hampshire following the contract re-negotiation in May, 2003. Energy produced during 2004 represented 98.5% of long-term averages compared to 97% of long-term averages during the prior year.

Operating expenses for the Hydroelectric Division during the fourth quarter of 2004 were $4.7 million, an increase over the $3.6 million spent in the fourth quarter of 2003 due primarily to higher repair, maintenance and operating costs at the Côte Ste. Catherine, Great Falls and Long Sault Rapids facilities. For 2004, Hydroelectric Division operating expenses of $17.4 million were higher than the $15.9 million in 2003 mainly due to these increased repair and maintenance costs.

The Hydroelectric Division's operating profit for the fourth quarter of 2004 was $5.8 million versus $7.9 million during the fourth quarter of 2003. For 2004, operating profit was $26.4 million compared to $29.0 million in 2003. Operating profit for 2004 was below management's expectations due to substantially weaker hydrologic conditions and higher divisional operating expenses, both encountered in the fourth quarter of 2004. Hydrologic conditions experienced during the first quarter of 2005 have generally reflected long-term average hydrology.

• The Fund intends to continue to enhance unitholder value by improving efficiency of hydroelectric operations and pursuing acquisitions which provide sustainable accretion to unitholders.





OUTLOOK

For the majority of 2004, the regions in which the Fund operates facilities generally enjoyed improved hydrologic conditions, providing generation levels closer to long-term averages. Although this trend reversed during the fourth quarter of 2004, average hydrologic conditions are again being observed in the first quarter of 2005. Assuming continuation of average hydrologic conditions, the Hydroelectric Division is expected to perform in accordance with management's expectations for the remainder of 2005.

In 2005, the Fund intends to continue to enhance unitholder value by improving efficiency of the hydroelectric operations, continuing to seek opportunities to structure attractive power purchase contracts and pursuing hydroelectric acquisitions which provide sustainable accretion to unitholders. Continued emphasis will be placed on acquisition of larger facilities which provide geographic diversification of regional hydrologic and market concentrations. In addition, the Fund will consider the rationalization of smaller generating facilities that may no longer fit the Fund's risk-return profile.

Certain hydroelectric generating facilities owned by the Fund qualify for consideration as "green" energy and the Fund plans to pursue revenue opportunities presented by the emerging markets for renewable energy credits in the United States and the trading of greenhouse gas credit emissions in Canada. The Fund also plans to pursue longer-term power purchase agreements for the sale of green energy from those facilities that are currently selling electricity in the open market.

COGENERATION

All figures in thousands of Canadian dollars except as noted

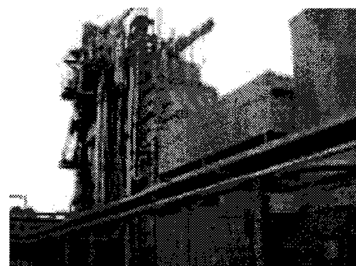
	Three Months Ended December 31		Year Ended December 31		Forecast Production
	2004	**2003**	**2004**	**2003**	**2005**
Performance (MW-hrs sold)	133,356	136,888	521,149	443,419	544,657
Revenues					
Energy Sales	$ 17,556	$ 17,179	$ 71,846	$ 61,890	
Expenses					
Operating Expenses	$ (12,066)	$ (12,162)	$ (50,597)	$ (42,758)	
Other Income	$ 749	$ 827	$ 4,024	$ 4,641	
Division Operating Profit (Includes Interest and Other Income)	$ 6,239	$ 5,844	$ 25,273	$ 23,773	

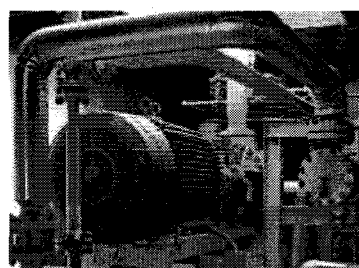
The Cogeneration Division posted revenue during the fourth quarter of 2004 of $17.6 million, compared to $17.2 million during the same period in 2003. During 2004, the Cogeneration Division produced revenue of $71.8 million, an increase over the $61.9 million recorded in 2003, with such increase partially attributed to the full-year inclusion of revenue from the Windsor Locks facility purchased in March, 2003. The Windsor Locks facility had provided additional revenue of approximately $8.9 million during the first quarter of 2004 compared to 2003 which helped offset the cost of two unplanned operational outages at the Sanger facility during the first and second quarters.

Fourth quarter operating expenses in the Cogeneration Division were $12.1 million compared to $12.2 million in the same period, 2003. For the year ended December 31, 2004, operating expenses were $50.6 million compared to $42.8 million in 2003 due to the inclusion of a full-year of expenses from the Windsor Locks facility. This facility incurred operating expenses of approximately $33.4 million in 2004, the first full year in which this asset was owned by the Fund. The Sanger facility experienced two unplanned gas turbine outages during the first and second quarters caused by a component failure. The cost of the required repairs was covered by insurance after taking into consideration an insurance deductible of US $300,000 per occurrence.

Operating profit for the Cogeneration Division in the fourth quarter increased to $6.2 million from $5.8 million in 2003. For the year ended December 31, 2004, operating profit increased to $25.3 million from $23.8 million in 2003. Operating profit for the fourth quarter met management's expectations. Operating profit for 2004 was below management's expectations primarily due to the unplanned outages at the Sanger facility incurred during the first and second quarters of 2004.

• The Fund anticipates increased revenue from electricity at Windsor Locks and increased sale of thermal energy at the Sanger Facility.





OUTLOOK

The Fund's focus for the Cogeneration Division will be on maintaining the reliable supply of generation from all facilities and pursuing opportunities to realize additional revenue. These opportunities include the sale of excess power generation, satisfaction of increasing electrical load requirements of the steam host at the Windsor Locks facility and sale of thermal energy at the Sanger facility. In addition, the Fund will continue to consider the sale of contracted natural gas when favourable pricing in the natural gas market exists.

ALTERNATIVE FUELS

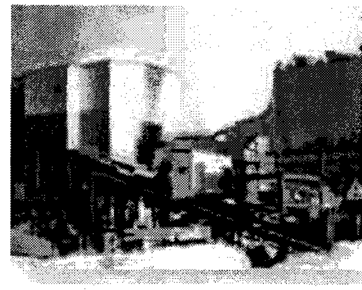
All figures in thousands of Canadian dollars except as noted

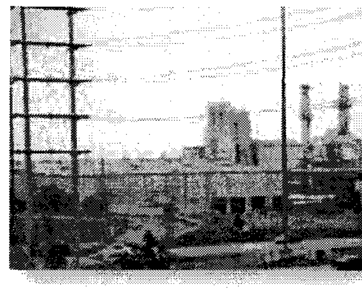
	Three Months Ended December 31		Year Ended December 31		Forecast Production
	2004	**2003**	**2004**	**2003**	**2005**
Performance (MW-hrs sold)	57,192	25,782	124,721	97,335	312,176
Performance (tonnes waste processed)	37,471	41,354	157,491	155,250	178,490
Revenues					
Energy Sales	$ 3,646	$ 1,587	$ 7,867	$ 6,423	
Waste Disposal Sales	3,503	4,333	14,086	14,650	
Total	$ 7,149	$ 5,920	$ 21,953	$ 21,073	
Expenses					
Operating Expenses	$ (5,262)	$ (3,241)	$ (15,124)	$ (12,895)	
Interest, Dividend and Other Income	$ 622	$ 95	$ 1,352	$ 1,150	
Division Operating Profit (Includes Interest, Dividend and Other Income)	$ 2,509	$ 2,774	$ 8,181	$ 9,328	

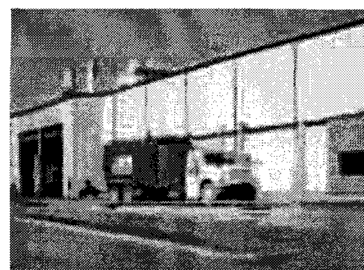
Revenue reported during the fourth quarter of 2004 increased to $7.1 million from $5.9 million in 2003, primarily due to the addition of the LFG Facilities at the end of the third quarter of 2004. Energy sales increased to $3.6 million in 2004 from $1.6 million in 2003. For the year ended 2004, the Alternative Fuels Division reported revenue of $22.0 million, representing an increase of approximately $0.9 million over the $21.1 million realized during 2003, attributed to electrical energy sales from the LFG Facilities that contributed $2.2 million in revenue for the fourth quarter of 2004.

Operating expenses incurred in the Alternative Fuels Division were $5.3 million in the fourth quarter of 2004, compared to $3.2 million incurred during the fourth quarter, 2003. The primary contributors to this increase were higher repair and maintenance costs at the Peel Energy-from-Waste facility and inclusion of post-acquisition operations, maintenance, repair and fuel costs at the LFG Facilities. For the year ended December 31, 2004, operating expenses were $15.1 million compared to $12.9 million during the prior year. The increase was due to higher operating costs for the Peel Energy-from-Waste and the inclusion of the costs relating to the newly acquired LFG Facilities. At the end of December 2004, the Fund recognized an expense of $1.9 million, representing the write-off of the balance of the book value of the Joliet facility as it was deemed that the facility was no longer economically viable.

The Alternative Fuels Division recorded an operating profit of $2.5 million during the fourth quarter of 2004 compared to $2.8 million reported in the same period in 2003. For the fourth quarter, the Alternative Fuels Division performed below management's expectations due to higher repair and maintenance costs and lower than expected revenue. For the year ended December 31, 2004, operating profit was $8.2 million compared to $9.3 million in 2003. The Alternative Fuels Division performed below management's expectations for the full year primarily due to higher than anticipated repair and maintenance costs incurred at the Peel Energy-from-Waste facility and legal costs incurred in respect of the Joliet facility.







• The Fund has agreed to sell thermal energy to an Industrial customer near the Peel Energy-from-Waste Facility.

OUTLOOK

Management is pleased to report that the Fund's Production Recovery Action Plan implemented in 2004 at the Peel Energy-from-Waste facility is beginning to produce favourable results. This plan includes equipment constraint identification, prioritization of production improvement initiatives, restructuring of plant management and improved employee training.

The acquisition in September, 2004 of an interest in the LFG Facilities, representing approximately 36MW of installed capacity, increased the total electrical generation capacity of the Fund by 6%. Approximately 66% of the installed capacity of the LFG Facilities is located at large open landfills that are continuing to accept waste including three regional landfills permitted for operation for at least 25 years located in the southern California basin. Substantial opportunity exists for expansion of the generating capacity of these facilities as waste accumulation continues to grow. In addition to the revenues from the sale of electricity, the Fund is able to enhance returns through the sale of certain renewable energy credits produced by these assets.

The Fund has entered into an agreement to sell steam from the Peel Energy-from-Waste facility to an industrial customer located in close proximity to the Peel Energy-from-Waste facility. To effect such sales, the Fund will be undertaking the installation of certain additional steam generation and transmission assets, anticipated to cost approximately $8.1 million. This project is expected to produce an internal rate of return in excess of 15% per annum over the 20-year term of the energy services agreement.

Management at the Peel Energy-from-Waste facility is in the process of renegotiating its collective bargaining agreement with its production employees. The current collective bargaining agreement expires April, 2, 2005.

The facilities owned by the Alternative Fuels Division are characterized as "green" energy. The Fund plans to pursue revenue opportunities presented by the emerging markets for renewable energy credits in the US and the trading of greenhouse gas credit emissions in Canada.

INFRASTRUCTURE

All figures in thousands of Canadian dollars except as noted

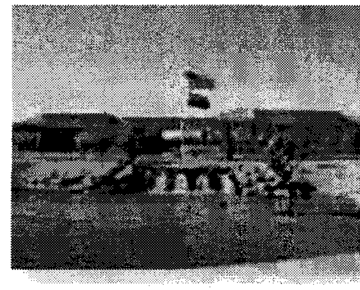
	Three Months Ended December 31 2004	2003	Year Ended December 31 2004	2003	Forecast Total Connections 2005
Water Reclamation Customers	20,703	18,831	20,703	18,831	22,546
Water Distribution Customers	19,318	17,948	19,318	17,948	20,812
Revenues					
Water Reclamation and Distribution	$ 5,739	$ 5,247	$ 23,456	$ 20,237	
Expenses					
Operating Expenses	$ (2,136)	$ (2,465)	$(10,849)	$ (9,165)	
Other Income	$ 1	$ 13	$ 9	$ 45	
Division Operating Profit (Incudes Other Income)	$ 3,604	$ 2,795	$ 12,616	$ 11,117	

Revenue earned by the Infrastructure Division during the fourth quarter of 2004 increased to $5.7 million from $5.2 million recorded during the same period in 2003. Demand from water distribution customers declined in the fourth quarter of 2004 as a result of higher than average precipitation in the geographic areas in which the majority of the Fund's water distribution assets are located. Strong organic growth from an expanding customer base continued during the fourth quarter, 2004. The water distribution customer count was 19,318, a 1.4% increase for the quarter. Water reclamation customer count was 20,703, a 2.4% increase for the quarter. The strong year-over-year growth was significant with water distribution customer count increasing 7.6% and water reclamation customer count rising by 9.9%.

For the year ended December 31, 2004, revenue increased to $23.5 million from $20.2 million in 2003 primarily as a result of organic growth through additional customer connections.

The Infrastructure Division incurred operating expenses of $2.1 million in the fourth quarter of 2004, from $2.5 million for the same period in 2003 primarily due to a year-to-date adjustment during the current period to reclassify certain expenses as administrative costs. For the year ended December 31, 2004, operating expenses increased to $10.8 million from $9.2 million in 2003. The increased costs for the full year resulted from additional costs related to the additional customer connections.

Operating profit for the fourth quarter of 2004 increased to $3.6 million in comparison to $2.8 million earned in the fourth quarter of 2003. While operating profit increased, it remained below management's expectations primarily due to higher operating costs at the Litchfield Park, Gold Canyon and Bella Vista facilities. For the year ended December 31, 2004, operating profit increased to $12.6 million from $11.1 million in 2003. Similarly, while 2004 operating profits continued to rise over those recorded for 2003, the results were below management's expectations primarily due to slower-than-expected growth and lower water sales due to heavy rains in the Phoenix area where the Fund's Litchfield Park facility is located.



• The Fund intends to pursue accretive acquisitions of water distribution and reclamation opportunities during 2005.

OUTLOOK

The Fund expects organic growth to continue within existing utilities throughout 2005, providing continued revenue and operating profit growth for the Infrastructure Division. The Fund also intends to pursue opportunities for adding new customers through providing water distribution and water reclamation services in geographic areas contiguous to existing Fund utilities.

The Fund is in the process of expanding certain existing facilities to meet increasing service demands including the wastewater treatment plant owned by the Gold Canyon Sewer Company. Phase I of the expansion was completed in 2004 and Phase II is expected to be completed during 2005. Upon completion of the planned changes, the Gold Canyon treatment facility will be capable of handling the high customer growth which is expected to continue over the next several years within the utility area. Within the Litchfield Park service area, several pipeline expansions were completed in 2004 that will facilitate continued land development and increasing customer connections over the next several years.

The Litchfield Park service area in Arizona is located in one of the fastest growing counties in the United States and intense growth is expected to have a positive impact on divisional revenue. Moderate growth also continues in the Infrastructure Division's service areas located in the east valley of central Arizona, southern Arizona and Texas resulting in anticipated overall growth in the Infrastructure Division comparable to that achieved over the past 12 months.

The Fund has entered into a purchase and sale agreement to acquire eight water and wastewater systems, which, in aggregate, serve approximately 7,000 equivalent residential connections located in Texas, Missouri and Illinois. Closing of this transaction is anticipated to occur in mid-March 2005.

During 2005, the Fund intends to pursue accretive acquisitions of water distribution and water reclamation opportunities to enhance unitholder value. The Fund will target utilities located in high-growth regions in the United States that provide predictable and sustainable cash flows.

ADMINISTRATIVE EXPENSES

	Three Months Ended December 31		Year Ended December 31	
	2004	**2003**	**2004**	**2003**
Administrative Expenses	$1,615	$1,631	$5,596	$5,577
Business Development Costs	–	–	–	572
Management Costs	196	196	777	710
Withholding Taxes	135	97	483	525
(Gain) / Loss on Foreign Exchange	873	(2,810)	(2,601)	(17,364)
Interest Expense	3,721	3,228	12,440	11,631
Income Taxes Expense (Recovery)	1,780	1,701	2,285	(4,408)

For the fourth quarter and the full year of 2004, administrative expenses remained constant when compared to the corresponding periods of 2003.

The weakening of the Canadian dollar against the U.S. dollar resulted in an unrealized foreign exchange loss of $0.9 million for the fourth quarter of 2004 compared to a gain of $2.8 million in the same period in 2003. For the full year, the Fund posted a foreign exchange gain of $2.6 million, of which $2.5 million is unrealized, compared to a foreign exchange gain of $17.4 million in 2003. The unrealized foreign exchange gain is primarily the result of fluctuations of the US dollar and its impact on the Fund's US dollar denominated debt obligations. At the end of the fourth quarter, the Fund had approximately $42.2 million in US dollar denominated debt.

Interest expense increased to $3.7 million in the fourth quarter of 2004, from $3.2 million in the fourth quarter, 2003. The increase is due to the combined effects of the issue of $85 million convertible debentures in the third quarter of 2004 offset by a decrease in interest expense due to maturity of the KMS convertible debentures in the second quarter of 2004 and the indebtedness outstanding under the Fund's line of credit being repaid from the proceeds of the $85 million convertible debenture offering. For the year ended December 31, 2004, interest expense increased to $12.4 million from $11.6 million in 2003.

During the fourth quarter of 2004, the Fund recorded an income tax expense of $1.8 million, including $1.4 million related to future income tax expense. The difference represents a current income tax expense. In the fourth quarter of the prior year, the Fund recorded an income tax expense of $1.7 million, substantially all of which was related to future income tax expense. For the year ended December 31, 2004, the Fund recorded an income tax expense of $2.3 million, of which $1.2 million was related to a future income tax expense with the difference of $1.1 million representing a current income tax expense. These results compare to a $4.4 million income tax recovery in the prior year, of which $5.6 million was a future income tax expense and the balance was a current income tax expense.

CASH AVAILABLE FOR DISTRIBUTION

	Three Months Ended December 31		Year Ended December 31	
	2004	**2003**	**2004**	**2003**
Cash Flow from Operating Activities	$12,090	$12,533	$66,434	$58,209
Changes in Working Capital	(1,255)	4,660	(7,553)	322
Operating Cash Flow before Working Capital Changes	**$10,835**	**$17,193**	**$58,881**	**$58,531**
Receipt of Principal on Notes Receivable	983	1,348	4,164	3,194
Decrease / (Increase) in Reserves	330	110	235	319
Repayment of Long-term Liabilities	(340)	(329)	(863)	(828)
Maintenance Capital Expenditures (net of capital grants and asset disposal)	217	(153)	(1,804)	(1,325)
Other	660	(769)	(726)	(1,523)
Cash Available for Distribution	**$12,685**	**$17,400**	**$59,887**	**$58,368**
Cash Available for Distribution per trust unit	0.18	0.26	0.87	0.86
Distribution to Unitholders	**$16,015**	**$15,600**	**$63,370**	**$62,402**
Distribution to Unitholders per trust unit	0.23	0.23	0.92	0.92

During the fourth quarter of 2004, cash available for distribution decreased to $12.7 million compared to $17.4 million in the same period of 2003. On a per unit basis, the Fund generated $0.18 of cash available for distribution in the fourth quarter of 2004, compared to $0.26 during the fourth quarter of 2003. For the year ended December 31, 2004, the Fund generated $59.9 million of cash available for distribution compared to $58.4 million during the same period in 2003. These results represent $0.87 per trust unit for the year ended December 31, 2004, comparing favourably to $0.86 per trust unit generated during 2003.

The Fund distributed $16.0 million for the fourth quarter of 2004 and $15.6 million for the fourth quarter of 2003. On a per unit basis, the Fund distributed $0.23 per trust unit for the fourth quarter in both 2004 and 2003. The number of units increased due to units issued as the consideration to KMS debenture holders tendering their securities in 2004. For the year ended December 31, 2004, the Fund distributed $63.4 million compared to $62.4 million during 2003. Per unit distributions remained at $0.92 per trust unit for both 2004 and 2003. The shortfall in cash available for distribution was funded from working capital.

DISTRIBUTION OUTLOOK FOR 2005

Management believes that with continuing average hydrologic conditions, the strong organic growth evident in water distribution and reclamation services, the additional generating capacity represented by the LFG Facilities, interest earned on advances under the subordinated debt commitment made to AirSource Power Fund I LP and the continued benefits of the portfolio diversification, cash generated by operations should be in line with or exceed current distribution levels for 2005.

LIQUIDITY AND CAPITAL RESERVES

At the end of 2004, the Fund had $34.2 million of cash and cash equivalents and positive net working capital of $17.2 million.

Long-term liabilities were $120.1 million at the end of 2004, compared to $165.1 million at the end of 2003.

In January 2005, the Fund re-negotiated its combined lines of credit available totalling $145 million in either Canadian or US dollar currency for operating and acquisition requirements with a syndicate of chartered banks. The renegotiated credit facility provides for a general operating line of $20 million, provision of letters of guarantee of approximately $32 million with the balance for acquisition funding purposes. At the end of 2004, the Fund had $30.0 million drawn on the credit facility in addition to $30.9 million represented by letters of guarantee that have been posted on behalf of the Fund. Under the terms of the renegotiated credit agreement, the Fund is required to pay a standby charge of 0.25% on the un-drawn portion of the credit facility, a reduction of 0.175% from the terms of the credit facility in force during 2004.

During 2005, the Fund anticipates to incur higher capital expenditures than incurred during 2004 due to continuing growth and regulatory requirements in the Infrastructure Division. Additional wastewater treatment capacity is likely to be required at the Litchfield Park facility in addition to the completion of the capacity increase currently underway at the Gold Canyon facility. In addition, the water distribution utilities owned by the Fund will be required to comply with new rules pertaining to arsenic levels coming into effect in the United States at the beginning of 2006. The Fund has also committed to invest approximately $8.1 million in steam generation and distribution equipment at the Peel Energy-from-Waste facility to enhance returns. The Fund anticipates financing these expenditures with cash flow generated from operations, the credit facility and additional trust unit offerings.

At the end of 2004, the Fund had a strong balance sheet with a long-term debt-to-equity ratio of 43%.

At the end of 2004, the Fund had the following contractual obligations for the next five years:

	2005	2006	2007	2008	2009
Long term debt obligations	$ 932	$ 1,017	$ 1,109	$ 1,216	$ 1,327
Other obligations	734	438	4,377	392	260
Total Obligations	**$ 1,666**	**$ 1,455**	**$ 5,486**	**$ 1,608**	**$ 1,587**

In addition to the above obligations, the Fund has commitments to pay certain additional amounts to the vendors of the Litchfield Park and Woodmark facilities which are tied to customer growth in these utilities. As the quantum of such growth is not determinable, management is unable to quantify these amounts. The Fund has obligations with respect to lease and land and/or water rights for certain hydroelectric facilities. These obligations are based on power production by these facilities and, since power production is related to future hydrologic conditions, such obligations are not quantifiable.

DEALING WITH ALGONQUIN POWER GROUP

During 2004, companies related to the Manager provided operations and technical services on a cost recovery basis, details of which are outlined in note 13 of the audited financial statements.

RISK MANAGEMENT

The Fund continues to enjoy the benefits of forward contracts to hedge its U.S. dollar exchange rate relative to expected future monthly cash flows. At the end of 2004, the Fund had forward contracts for 2005 totalling US $24.3 million at an average rate of $1.41 per US dollar. The Fund has entered into forward contracts that provide similar fixed exchange rate protection for 2006 to the end of 2009 totalling US$74.5 million carrying an average rate of $1.38.

The Fund has fixed the price of its natural gas exposure until 2006 at the Sanger facility and to 2007 at the Peel Energy-from-Waste facility. The power sales and natural gas supply agreements in place in respect of the natural gas powered generating facilities owned by the Fund have been structured to insulate the Fund from the economic impacts of the changing market price of natural gas. Under the terms of the energy services agreement relating to the sale of steam from the Peel Energy-from-Waste facility to an industrial customer, the Fund has been able to mitigate against natural gas price exposure at the Peel Energy-from-Waste facility for the 20-year term of this agreement.

The Fund has adequate insurance on all of its facilities. This coverage includes property and casualty, boiler and machinery and liability insurance.

CRITICAL ACCOUNTING ESTIMATES

The Fund recognizes revenue derived from energy sales at the time energy is delivered. Water reclamation and distribution revenue is recognized when delivered to customers. Revenue from waste disposal is recognized on an actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts are recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected is deferred.

The Fund books deferred credits received by the Infrastructure Division which relate to advances from developers for water and sewage main extensions received. These advances usually carry repayment terms based on the revenue generated by the development in question ranging for a term of 10 years. At the end of the payment term, the unpaid portion of the advance converts to contribution in aid of construction and is not required to be repaid to the developer. The Fund records the deferred credits based on its expected repayments as determined by historical experience and industry practice.

The Fund records at cost capital assets such as land, facilities and equipment. Improvements that increase or prolong the service life or capacity of an asset are also capitalized at cost. Intangible assets such as power purchase contracts acquired, licensing costs and customer relationship costs are recorded at cost. The Fund reviews capital and intangible assets for permanent impairment whenever events or changes in circumstances indicate the carrying amounts may not be recoverable.

The Fund enters into forward contracts to hedge against its exposure to the US dollar. Gains and losses from these activities are reported as adjustments to the related revenue or expense account as they are settled.

OUTLOOK

The Fund will continue to identify opportunities to optimize the performance of its portfolio. Management is focusing its efforts on integrating recently acquired facilities and identifying efficiency opportunities to enhance unitholder value. Assuming continuing average long-term hydrologic conditions, the strong organic growth evident in water distribution and reclamation services, the additional generating capacity represented by the LFG Facilities, interest earned on advances under the subordinated debt commitment made to AirSource Power Fund I LP and the continued benefits of the portfolio diversification, cash generated by the operations should be in line with or exceed current distribution levels for 2005.

The Fund will continue to look for opportunities to expand and continue its diversification strategy.

The Fund continues to be an industry leader in the areas of the environment and health and safety. The Fund maintains continuous health and safety training for all its operations and maintenance staff. All of the Fund's facilities are in compliance in all material respects with local and federal environmental regulations. The Fund continues to upgrade the facilities' environmental controls utilizing best available technology.

The Fund plans to invest in information technology to reduce administrative costs by continuing the implementation of supply chain management systems and integrated billing and customer protocols.

In keeping with the emerging Ontario Securities Commission requirements, the Fund is in the process of completing the review and documentation of its controls and procedures for annual certification of the financial statements.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2004 and 2003.

$ millions except per trust unit amounts

2004	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Total
Revenues	$ 37.2	$ 41.9	$ 40.7	$ 40.7	$ 160.5
Net earnings (loss)	3.3	8.1	11.5	(0.1)	22.8
Net earnings per trust unit	0.05	0.12	0.16	0.00	0.33
Total assets	812.5	809.0	834.2	823.9	823.9
Long-term debt	186.4	189.7	214.6	226.2	226.2
Distribution per trust unit	0.23	0.23	0.23	0.23	0.92

2003	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Total
Revenues	$ 27.6	$ 42.2	$ 38.1	$ 39.7	$ 147.6
Net earnings	6.5	21.5	10.0	6.5	44.5
Net earnings per trust unit	0.10	0.32	0.15	0.09	0.66
Total assets	828.7	829.0	822.2	808.6	808.6
Long-term debt	185.7	178.6	177.8	185.4	185.4
Distribution per trust unit	0.23	0.23	0.23	0.23	0.92

RECENTLY ISSUED CANADIAN ACCOUNTING STANDARDS

Hedging Relationships

Accounting Guideline 13 ("AcG 13"), issued by the Canadian Institute of Chartered Accountants, is effective for the Fund's 2004 fiscal year. AcG 13 specifies the circumstances in which hedge accounting is appropriate, including the identification, documentation, designation and effectiveness of hedges, and the discontinuance of hedge accounting. The Fund has entered into a series of foreign exchange forward contracts, which are classified as hedging relationships, in order to mitigate its foreign exchange risk related to the U.S./Canadian dollar exchange rate. The Fund considers that these hedge instruments are effective hedges. The Fund reviews the effectiveness of hedge instruments on a quarterly basis. If management concluded that these hedge instruments were no longer effective, they would be marked-to-market and the effect would be recorded in income.

Asset Retirement Obligations

Section 3110 of the CICA Handbook, Asset Retirement Obligations, is applicable for the Fund's 2004 fiscal year. Under this standard, the asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's useful life and included in depreciation and amortization expense on the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Actual expenditures incurred are charged against the accumulated obligation. During the first quarter of 2004, the Fund completed an analysis of existing properties. This analysis reviewed existing contracts (leases, etc.) and current statutory requirements, and management has determined that a provision for retirement obligations is not currently required.

Impairment of Long-Lived Assets

Section 3063 of the CICA Handbook, Impairment of Long-Lived Assets, is applicable for the Fund's 2004 fiscal year. Under this standard, an impairment loss should be recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. There was no material impact on the Fund's earnings per unit in the 2004 fiscal year.

NOTE Certain statements contained in the information herein are forward-looking and reflect the Fund's and its Manager's views with respect to future events. Since forward-looking statements address future events and conditions, by their very nature, they involve inherent risks and uncertainties. Forward-looking statements are not guarantees of the Fund's future performance or results and are subject to various factors, including, but not limited to, assumptions such as those relating to: the performance of the Fund's assets, commodity market prices, interest rates and environmental and other regulatory requirements. Although the Fund and its Manager believe that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of the dates hereof. The Fund and its Manager are not obligated nor do either of them intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise.

AUDITOR'S REPORT

We have audited the consolidated balance sheets of Algonquin Power Income Fund as at December 31, 2004 and 2003 and the consolidated statements of earnings and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Toronto, Canada
March 8, 2005

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2004 AND 2003

(in thousands of Canadian dollars)

	2004	2003 (Restated Note 21)
Assets		
Current Assets		
Cash and cash equivalents	$ 34,197	$ 21,238
Accounts receivable	25,343	20,297
Prepaid expenses	1,790	1,530
Current portion of notes receivable (note 4)	2,589	1,478
Future income tax asset (note 12)	18	105
	$ 63,937	$ 44,648
Long-term investments (note 4)	48,561	59,190
Future non-current income tax asset (note 12)	6,425	6,809
Capital assets, net of accumulated amortization (note 5)	610,756	610,380
Intangible assets, net of accumulated amortization (note 6)	83,677	82,334
Funds held in reserve	3,728	3,963
Deferred costs (net of accumulated amortization of $1,383, 2003 - $657)	6,815	1,300
	$ 823,899	$ 808,624
Liabilities		
Current Liabilities		
Accounts payable and accrued liabilities	30,481	19,907
Due to Algonquin Power Group (note 13)	1,826	1,035
Cash distribution payable	10,677	10,400
Current portion of long-term liabilities (notes 8 and 10)	1,666	1,961
Current income tax liability	596	1,142
Future income tax liability (note 12)	1,449	866
	$ 46,695	$ 35,311
Long-term liabilities (notes 7 and 8)	120,085	165,117
Convertible debentures (note 9)	85,000	–
Other long-term liabilities (note 10)	8,960	9,622
Deferred credits	12,124	10,627
Future non-current income tax liability (note 12)	55,764	53,012
Minority interest (note 8)	–	15,059
Unitholders' equity		
Trust units (note 11)	654,176	638,213
Deficit	(158,905)	(118,337)
	$ 495,271	$ 519,876
Commitments and contingencies (notes 4 and 14)		
Guarantees (note 20)		
	$ 823,899	$ 808,624

See accompanying notes to the consolidated financial statements

Approved by the Trustees

CONSOLIDATED STATEMENTS OF EARNINGS & DEFICIT
DECEMBER 31, 2004 AND 2003

(in thousands of Canadian dollars except as noted and per trust unit)

	2004	2003
Revenue		
Energy sales	$ 122,981	$ 112,726
Waste disposal fees	14,086	14,650
Water reclamation and distribution	23,456	20,237
	160,523	147,613
Expenses		
Operating (note 13)	94,012	80,680
Amortization of capital assets	27,762	25,424
Amortization of intangible assets	6,465	4,950
Management costs (note 13)	777	710
Administrative expenses	5,596	5,577
Business development	-	572
Withholding taxes	483	525
(Gain) / loss on foreign exchange	(2,601)	(17,364)
	132,494	101,074
Earnings before undernoted	28,029	46,539
Interest expense	(12,440)	(11,631)
Interest, dividend and other income	6,681	6,608
Income from note receivable prepayment	3,634	-
	(2,125)	(5,023)
Earnings before income taxes and minority interest	25,904	41,516
Current income taxes (note 12)	1,105	1,175
Future income taxes (note 12)	1,180	(5,583)
	2,285	(4,408)
Minority interest	817	1,417
Net earnings	22,802	44,507
Deficit, beginning of year	(118,337)	(100,442)
Cash distributions (note 16)	(63,370)	(62,402)
Deficit, end of year	$ (158,905)	$ (118,337)
Basic and diluted net earnings per trust unit (note 17)	$ 0.33	$ 0.66

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS
DECEMBER 31, 2004 AND 2003

(in thousands of Canadian dollars except as noted and per trust unit)

	2004	2003
Operating Activities		
Net earnings	$ 22,802	$ 44,507
Items not affecting cash		
Amortization of capital assets	27,762	25,424
Amortization of intangible assets	6,465	4,950
Other amortization	2,331	2,934
Minority interest	817	1,417
Distribution received in excess of equity income	(16)	242
Future income taxes	1,180	(5,583)
(Gain) / loss on foreign exchange	(2,460)	(15,360)
	58,881	58,531
Changes in non-cash operating working capital	7,553	(322)
	66,434	58,209
Financing Activities		
Cash distributions	(63,370)	(62,402)
Issue costs of trust units	(700)	-
Convertible debenture issue (note 9)	85,000	-
Expenses of convertible debenture issue (note 9)	(4,100)	-
Deferred costs	(2,305)	(641)
Increase in long-term liabilities	30,000	112,833
Decrease in long-term liabilities	(71,969)	(42,228)
Other	(1,117)	(358)
Deferred credits	426	411
	(28,135)	7,615
Investing Activities		
Decrease in reserve funds	235	319
Receipt of principal on notes receivable	21,988	3,194
Additions to capital assets	(17,336)	(12,071)
Additions to intangible assets	-	(289)
Power Purchase Contract Renegotiation (note 3)	-	25,357
Acquisition of notes receivable	(13,917)	-
Acquisitions of operating entities net of cash acquired (note 2)	(15,159)	(84,895)
	(24,189)	(68,385)
Effect of exchange rate differences on cash and cash equivalents	(1,151)	(1,039)
Increase / (decrease) in cash and cash equivalents	12,959	(3,600)
Cash and cash equivalents, beginning of year	21,238	24,838
Cash and cash equivalents, end of year	$ 34,197	$ 21,238
Supplemental disclosure of cash flow information		
Cash paid during the year for interest expense	$ 9,441	$ 9,551
Cash paid during the year for income taxes	$ 1,624	$ 854
Non-cash issue of trust units to retire convertible debentures of KMS (note 8)	$ 16,663	$ -

See accompanying notes to the consolidated financial statements

NOTES

DECEMBER 31, 2004 AND 2003

(in thousands of Canadian dollars)

Algonquin Power Income Fund (the "Fund") is an open-ended, unincorporated trust established pursuant to the Declaration of Trust dated September 8, 1997, as amended, under the laws of the Province of Ontario. The Fund's principal business activity is the ownership, directly or indirectly, of generating and infrastructure facilities.

The Fund is managed by Algonquin Power Management Inc. ("APMI"), a company wholly-owned by the shareholders of Algonquin Power Corporation Inc. ("APC"). A subsidiary of APC, Algonquin Power Systems Inc. ("APS"), is responsible for the operation of the Fund's facilities. Algonquin Water Services LLC ("AWS"), a partnership jointly owned by APC and the Fund, manages and operates the water reclamation and distribution facilities in Arizona. Collectively, these entities are referred to as the Algonquin Power Group.

1. Significant accounting policies

(a) New accounting policies

(i) Asset retirement obligations:

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheets when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and included in amortization expense on the consolidated statement of earnings and deficit. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statement of earnings and deficit. Actual expenditures incurred are charged against the accumulated obligation.

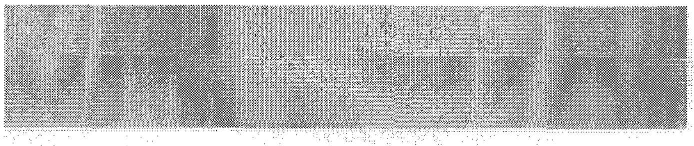
The Fund completed an analysis of existing properties. This analysis reviewed existing contracts and current statutory requirements and management has determined that a provision for retirement obligations is not currently required.

(ii) Derivatives contracts

The Fund enters into forward contracts to hedge against possible fluctuations in its exposure to the U.S. dollar. Gains and losses from these activities are reported as adjustments to the related revenue account as they are settled and no balance is carried on the consolidated balance sheet.

The Fund's policy is not to utilize derivative financial instruments for trading or speculative purposes.

The Fund formally documents all relationships between hedging instruments and hedged items as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Fund also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.



(iii) Impairment of long-lived assets

The Fund reviews capital assets and intangible assets for permanent impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. Recoverability is measured by comparing the carrying amount of an asset to expected future cash flows. If the carrying amount exceeds the expected future cash flows, the asset is written down to its fair market value.

(b)Basis of consolidation

The consolidated financial statements of the Fund have been prepared in accordance with accounting principles generally accepted in Canada and include the consolidated accounts of all of its subsidiaries. The Fund consolidates its proportionate share in the Campbellford Limited Partnership ("Campbellford") and the Valley Power Limited Partnership.

All significant intercompany transactions and balances have been eliminated.

(c)Cash and cash equivalents

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of 90 days or less.

(d)Funds held in reserve

Cash reserves segregated from the Fund's cash balances are maintained in accounts administered by a separate agent and disclosed separately in these consolidated financial statements as the Fund cannot access this cash without the prior authorization of parties not related to the Fund.

(e)Capital assets

Capital assets such as land, facilities and equipment are recorded at cost. Development costs, including the cost of acquiring or constructing facilities together with the related interest costs during the period of construction, are capitalized. Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

The facilities, equipment and overhauls are amortized on a straight-line basis over their estimated useful lives. For facilities, these periods range from 15 to 40 years. Facility equipment and overhauls are amortized over 3 to 6 years.

(f) Intangible assets

Power purchase contracts acquired are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 15 years from date of acquisition.

The costs attributable to establishing exemptions from Federal Energy Regulatory Commission licensing requirements in the United States are being amortized on a straight-line basis over 5 years.

Customer relationships are amortized on a straight-line basis over 40 years.

(g) Notes receivable

Notes receivable are carried at cost. A provision for credit losses on notes receivable is charged to the statement of earnings and deficit to cover any losses of principal and accrued interest.

(h) Deferred costs

Deferred costs, which include the costs of arranging the credit facility, costs associated with periodic customer rate reviews with the utility governing bodies for the water reclamation and distribution facilities and costs of various reorganizations which provide benefits for a number of years, are amortized on a straight-line basis over the term of the expected benefit, being 2 to 5 years.

(i) Long-term investments

Investments in which the Fund has significant influence, but not control or joint control, are accounted using the equity method. The Fund records its share in the income or loss of its investees in interest, dividend and other income in the consolidated statement of earnings and deficit. All other equity investments where the Fund does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and are adjusted only for other-than-temporary declines in fair value, distributions of earnings and additional investments.

(j) Deferred credits

Certain of the water companies receive advances from developers for water and sewage main extensions. The amounts advanced are generally repaid over a period of 10 years based on 10% of the revenues generated by housing/development in the area developed. Advances not refunded within ten years do not require repayment. The estimate of non-refundable amounts is credited against capital assets. The Fund also receives contributions in aid of construction with no repayment requirements in which the full amount is immediately treated as a capital grant and netted against capital assets.

Deferred water rights result from a hydroelectric generating facility that has a 50-year water lease with the first 10 years of the water lease requiring no payment. An average rate was estimated over the life of the lease and a deferral was booked based on this estimate which is being drawn down in the last 40 years.

(k) Recognition of revenue

Revenue derived from energy sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Water reclamation and distribution revenues are recorded when delivered to customers.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts is recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected rate is deferred.

Interest and dividend income from long-term investments is recorded as earned.

(l) Foreign currency translation

The Fund's United States subsidiaries and partnership interests are considered to be functionally integrated with the Canadian operations. All monetary assets and liabilities denominated in United States dollars are translated into Canadian dollars at year-end exchange rates, whereas non-monetary assets and liabilities are translated at the rate in effect at the transaction date. The revenues and expenses of these integrated operations are translated at the average rate of exchange in effect during the period. The foreign currency translation adjustment is reflected in the consolidated statement of earnings and deficit. Amortization of assets translated at historical exchange rates are translated at the same exchange rate as the assets to which they relate.

(m) Income taxes

As the Fund is an unincorporated trust, it is entitled to deduct distributions to unitholders to the extent of its taxable income and consequently, it is expected that the Fund will not be liable for any material tax as this will be the responsibility of the individual unitholder. Any provision for income taxes will relate solely to the income taxes of the Fund's wholly- owned subsidiaries.

Income taxes are accounted for using the asset and liability method. Future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the year that includes the date of enactment or substantive enactment.

A valuation allowance is recorded against future tax assets to the extent that it is more likely than not that the future tax asset will not be realized.

(n) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of capital assets and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of future tax assets, the portion of aid-in construction payments that will not be repaid, and the fair value of financial instruments and derivatives. These estimates and valuation assumptions are based on present conditions and management's planned course of action as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Acquisitions

On September 30, 2004, the Fund acquired an interest in 12 landfill gas-powered generating stations ("LFG Facilities") representing approximately 36MW of installed capacity for a total consideration of $11,374 (U.S. $9,000). The majority of the LFG Facilities were commissioned in the late 1990s. The electricity produced is sold to a number of large utilities pursuant to long-term power purchase agreements with an average termination date of 2011.

The acquisition has been accounted for using the purchase method, with earnings from operations included from the date of acquisition.

The consideration paid by the Fund has been allocated to net assets acquired as follows:

	Alternative Fuels
Working capital	$ 1,350
Capital assets	8,621
Intangible assets	1,746
Total purchase price	11,717
Less: cash acquired	(343)
Cash consideration paid	$ 11,374

Intangible assets represent the value of power purchase contracts acquired with the LFG Facilities and are amortized over the remaining life of the contracts from date of acquisition ranging from 2 to 17 years.

On March 10, 2003 the Fund acquired a 56MW cogeneration generating facility in Windsor Locks, Connecticut and the related power sales contracts for total consideration of $44,009 (U.S. $30,028). The Windsor Locks generating station sells electricity to Connecticut Light and Power Company pursuant to a long-term power purchase agreement ending in 2010. In addition, the facility delivers steam energy and a small portion of electricity to a speciality fiber composites mill located adjacent to the facility pursuant to an energy services agreement ending in 2018.

On February 25, 2003 the Fund acquired the shares of Litchfield Park Services Company ("Litchfield Park") located in Phoenix, Arizona for $34,928 (U.S. $23,401) in the Infrastructure operating segment. At December 31, 2004 the company services approximately 24,500 water and wastewater customers.

The acquisitions have been accounted for using the purchase method, with earnings from operations included since the date of acquisition. The consideration paid by the Fund has been allocated to net assets acquired as follows:

	Cogeneration	Infrastructure	Total
Working capital	$ –	$ (470)	$ (470)
Funds held in reserve	–	1,786	1,786
Capital assets	31,614	67,858	99,472
Intangible assets	12,395	7,220	19,615
Long-term liabilities assumed	–	(20,981)	(20,981)
Other long-term liabilities assumed	–	(2,445)	(2,445)
Deferred credits	–	(2,128)	(2,128)
Future non-current income tax liability	–	(15,912)	(15,912)
Total purchase price	44,009	34,928	78,937
Less: cash acquired	–	(1,452)	(1,452)
Cash consideration paid	$ 44,009	$ 33,476	$ 77,485

Intangible assets in cogeneration include power purchase contracts that are amortized over the term of the contracts from 6 to 15 years. Intangible assets in infrastructure include customer relationships that are amortized over 40 years.

In accordance with the purchase and sale agreements of Litchfield Park, Woodmark Utility Company and Gold Canyon Sewer Company, additional amounts are required to be paid to the vendors for additional customers connected with the different facilities. For Litchfield Park, these payments continue until 2008 and for Woodmark until 2007. There are no further payments required for Gold Canyon. The additional payments are capitalized as part of the customer relationship intangible asset, gross of future income taxes of $2,279 (2003 -$ 4,658).

	2004	2003
Litchfield Park	$ 3,626	$ 7,039
Woodmark	159	-
Gold Canyon	-	371
	$ 3,785	$ 7,410
In US $	$ 2,944	$ 5,635

3. Power purchase contract renegotiation

During 2003, the Fund completed the renegotiation of 13 power purchase agreements with rate orders with Public Service Company of New Hampshire ("PSNH"). This represents the total New Hampshire hydroelectric portfolio of the Fund. The total proceeds from this transaction were $28,295 (US$20,437). Of the total proceeds, $2,938 (US$2,122) has been placed into escrow pending the resolution of payment of certain lease obligations with the State of New Hampshire. The financial statements do not reflect any balance for the funds held in escrow as the certainty of the Fund receiving these proceeds is not known at this time. The net proceeds of $25,357 were used to pay down debt and fund working capital. The respective assets of the New Hampshire operations have been reduced by the amount of the net proceeds. Accordingly, no gain or loss has been recognized. The Fund continues to own and operate the 13 hydroelectric generating facilities and sells all the electrical output from the facilities to PSNH at current market rates.

4. Long-term investments

	2004	2003
Debt and share interests in four (2003 - five) generating facilities, ranging from 12.1% to 32.4% interest	$ 30,556	$ 52,315
A 45% partnership interest in the Algonquin Power (Rattle Brook) Partnership	3,787	3,860
	34,343	56,175
Campbellford Note		
Note bearing interest of 9.9415% repayable in monthly blended installments (principal and interest) of $32, maturing February 28, 2015.	3,023	3,213
Across America Note		
Note bearing interest of 12.00% repayable in quarterly installments, (principal and interest) of US$ 635, maturing January 31, 2008	8,004	-
Airsource Note		
Note bearing interest of 11.189% maturing September 30, 2014. Interest decreases to 10.739% after conversion. No principal payments until January 1, 2009.	5,512	-
Other	268	1,280
	16,806	4,493
	51,150	60,668
Less: current portion	2,589	1,478
	$ 48,561	$ 59,190

The notes above are secured by the underlying assets of the respective facilities.

On September 30, 2004, the Fund provided debt financing in the amount of $8,004 (U.S. $6,650) to Across America LFG LLC ("Across America") a majority owned subsidiary of a Fortune 50 company. Across America through its subsidiaries owns and manages the landfill gas collection systems which provide landfill gas to the LFG Facilities. The balance due within the year in the amount of $2,104 (US$ 1,748) is included as part of the current portion of notes receivable.

During the fourth quarter of 2004, the Fund agreed to provide between $69,200 and $90,800 in subordinated debt to AirSource Power Fund I LP, a 99 MW wind energy facility to be constructed near St. Leon, Manitoba. As of December 31, 2004, the Fund has provided financing in the amounts of $5,512.

On April 30, 2004, the loan to Cardinal Power of Canada LLP, the owner of the Cardinal Power Cogeneration facility, was repaid. The Fund received proceeds of $22,200, of which $18,600 represented the principal outstanding plus accrued interest and the remaining $3,634 represented a prepayment fee.

5. Capital assets

	Cost	2004 Accumulated amortization	Net book value
Land	$ 11,504	$ -	$ 11,504
Facilities	676,120	85,228	590,892
Equipment	12,623	4,263	8,360
	$ 700,247	$ 89,491	$ 610,756

Facilities include $89,889 (2003 - $90,693) of net assets under capital lease, $849 (2003 - $0) of construction in process. In addition $18,557 (2003 - $1,234) of contributions received in aid of construction have been credited to facilities' cost.

At the end of 2004, the Fund wrote off the cost and the accumulated amortization related to the Joliet facility. Cost written off amounted to $2,476 and the accumulated amortization totaled $1,444, for a net book value of $ 1,032 which has been included in amortization expense. Management deemed that the facility was no longer economically viable.

The Fund has entered into an agreement to sell steam from the Peel Energy-from-Waste facility to an industrial customer located in close proximity. To effect such sales, the Fund will incur the costs of certain additional steam generation and transmission assets. The Fund has committed to contractual arrangements to complete the project totaling approximately $8,100. The Fund has incurred amounts totaling $849 included in assets under construction. Cash flow generated from this project in excess of 15% will be shared with APC.

	Cost	2003 Accumulated amortization	Net book value (Restated Note 21)
Land	$ 11,444	$ -	$ 11,444
Facilities	651,714	62,627	589,087
Equipment	12,616	2,767	9,849
	$ 675,774	$ 65,394	$ 610,380

6. Intangible assets

	Cost	2004 Accumulated amortization	Net book value
Power purchase contracts	$ 73,966	$ 11,417	$ 62,549
Customer relationships	21,423	528	20,895
Licenses and agreements	696	463	233
	$ 96,085	$ 12,408	$ 83,677

	Cost	2003 Accumulated amortization	Net book value
Power purchase contracts	$ 74,044	$ 7,280	$ 66,764
Customer relationships	15,361	83	15,278
Licenses and agreements	1,044	752	292
	$ 90,449	$ 8,115	$ 82,334

Included in amortization of intangible assets is the write off of the Joliet power and gas contract for an amount of $900 (note 5).

7. Revolving credit facility

In January 2005, the Fund renegotiated its revolving credit agreement increasing the availability from $115,000 to $145,000 with a syndicate of Canadian banks, maturing August 31, 2006. The facility includes a $20,000 operating line. At December 31, 2004, $30,000 (2003 - $70,910) has been drawn on the revolving credit facility and no amount was outstanding on the operating line. In addition, the availability of the revolving credit facility has been reduced by $30,878 (2003 $30,669) for certain outstanding letters of credit. The terms of the credit agreement require the Fund to pay a standby charge of 0.25% on the unused portion of the revolving credit facility and 1.0%, plus the banker's acceptance or LIBOR interest rates on the drawn portion of the revolving credit facility. In addition the Fund has to maintain certain financial covenants. The facility is secured by a fixed and floating charge over all Fund entities.

8. Long-term liabilities

	2004	2003
Senior Debt Long Sault Rapids		
Interest at rates varying from 10.16% to 10.21% repayable in monthly blended installments of $402, maturing December, 2028.	$ 43,310	$ 43,710
Senior Debt Chute Ford		
Interest rate of 11.55% repayable in monthly blended installments of $64, maturing April, 2020.	5,473	5,596
Sanger Bonds		
California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, payable monthly, maturing September, 2020. U.S. $19,200. The effective interest rate for 2004 is 1.29%. (2003 – 1.11%).	23,109	24,814

(Table continued on next page)

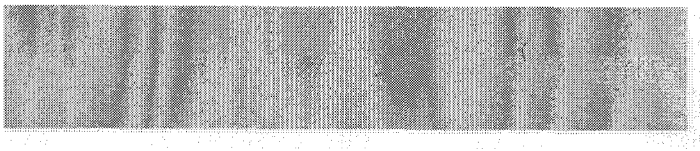
(Table continued from previous page)	2004	2003
KMS Convertible Debentures		
Interest rate of 10%: interest payable semi-annually June and December, maturing June, 2004.	-	751
Bella Vista Water Loans		
Water Infrastructure Financing Authority of Arizona interest rates of 6.10% and 6.26% repayable in monthly and quarterly installments, maturing December, 2017 and March, 2020. The balance of these notes at December 31, 2004 was U.S. $141 and U.S. $1,872 respectively (2003 – U.S.$147 and U.S. $1,937).	2,422	2,693
Litchfield Park Services Company Bonds		
1999 and 2001 IDA Bonds. Interest rates of 5.87% and 6.71% repayable in semi-annual installments, maturing October 2023 and October 2031. The balance of these notes at December 31, 2004 was U.S. $5,254 and U.S. $8,423, respectively, (2003 – U.S. $5,417 and U.S $8,457).	16,462	17,931
Revolving credit facility (Note 7)		
Revolving line of credit interest rate is equal to bankers' acceptance or LIBOR plus 125 basis points. The effective rate of interest for 2004 was 4.56% (2003 – 4.57%).	30,000	70,910
Other	241	308
	$ 121,017	$ 166,713
Less: current portion	(932)	(1,596)
	$ 120,085	$ 165,117

Each of the facility level debt is secured by the respective facility with no other recourse to the Fund. The loans have certain financial covenants which must be maintained on a quarterly basis. Interest paid on the long-term liabilities was $12,000. (2003 – $11,201)

Principal payments due in the next five years and thereafter are:

2005	$ 932
2006	31,017
2007	1,109
2008	1,216
2009	1,327
Thereafter	85,416
	$ 121,017

During the second quarter 2004, the Fund completed the acquisition of the remaining 52.7% of the outstanding principal amount of the convertible debentures of KMS Power Income Fund by issuing 1,803,980 trust units of the Fund for total consideration of $16,663. This transaction brought the ownership to 100% and eliminated all minority interest.



9. Convertible debentures

On July 20, 2004, the Fund issued 85,000 convertible unsecured subordinated debentures at a price of $1 per debenture for gross proceeds of $85,000 and net proceeds of $80,900. The debenture issue costs of $4,100 are deferred and amortized over the term of the convertible debentures. The debentures are due July 31, 2011 and bear interest at 6.65% per annum, payable semi-annually in arrears on January 31 and July 31 each year starting January 31, 2005. The convertible debentures are convertible into trust units of the Fund at the option of the holder at a conversion price of $10.65 per trust unit, being a ratio of approximately 93.8967 trust units per $1 principal amount of debentures in trust units or cash. The debentures may not be redeemed by the Fund prior to July 31, 2007. The Fund performed an evaluation of the embedded holder option and determined that its value was nominal and as a result the entire amount of the debenture is classified as a liability.

Total interest on the convertible debentures in 2004 was $2,555.

10. Other long-term liabilities	**2004**	**2003**
Joliet Subsidy Loan		
In accordance with Illinois law, a significant portion of the revenue received by KMS Joliet for the sale of electricity to the utility represents a subsidy. Repayment arrangements satisfactory to the State of Illinois must be implemented by 2007. U.S. $3,277.	$ 3,942	$ 3,915
Melo Roos		
Obligation for real estate taxes for the Sanger plant due October 1, 2011 at interest rates varying from 4.75% to 5.55%. U.S. $1,370 (2003 – U.S.$1,530)	1,649	1,977
Customer Deposits	2,850	3,212
Capital Leases	853	508
Other	400	375
	$ 9,694	$ 9,987
Less: current portion	(734)	(365)
	$ 8,960	$ 9,622

Principal payments due in the next five years and thereafter are:

2005	$ 734
2006	438
2007	4,376
2008	392
2009	260
Thereafter	3,494
	$ 9,694

Interest paid on other long-term liabilities was $440. (2003 – $430).

11. Trust units

Authorized trust units

The Declaration of Trust provides that an unlimited number of units may be issued. Each unit represents an undivided beneficial interest in any distribution from the Fund and in the net assets in the event of termination or wind-up. All units are the same class with equal rights and privileges.

Trust units are redeemable at the holder's option at amounts related to market prices at the time subject to a maximum of $250 in cash redemptions in any particular calendar month. Redemptions in excess of this amount shall be paid by way of a distribution in kind of a pro rata amount of certain of the Fund's assets, including the securities purchased by the Fund, but not to include the generating facilities.

Issued trust units

	Number of units	Amount
Balance as at December 31, 2003 and 2002	$ 67,887,612	$ 638,213
Issued pursuant to acquisition of the remaining 52.7% of the outstanding principal amount of convertible debentures of KMS Power Income Fund. (Note 8)	1,803,980	16,663
Issue costs		(700)
Balance as at December 31, 2004	$ 69,691,592	$ 654,176

12. Income taxes

The provision for income taxes in the consolidated statements of earnings represents an effective tax rate different than the Canadian enacted statutory rate of 33.66% (2003 – 35.6%). The differences are as follows:

	2004	2003
Earnings before income tax and minority interest	$ 25,904	$ 41,516
Less: income taxed directly in hands of unitholders, not the Fund	(36,090)	(32,817)
Earnings / (losses) of taxable entities	(10,186)	8,699
Computed income tax expense (recovery) at Canadian statutory rate	(3,429)	3,097
Increase (decrease) resulting from:		
Change in substantively enacted tax rate	-	1,218
Operating in countries with different income tax rates	996	1,121
Valuation allowances	6,090	4,535
Manufacturing and processing deduction	53	14
Large corporations tax, alternative minimum tax and state taxes	635	222
Unrealized foreign exchange rate difference	2,296	(2,302)
Unrealized foreign exchange rate differences on US entity debt	(5,614)	(12,663)
Other	1,258	350
Income tax expense / (recovery)	$ 2,285	$ (4,408)

The tax effect of temporary differences at the Fund's subsidiaries that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2004 and 2003 are presented below:

	2004	2003 (Restated Note 21)
Future tax assets:		
Non-capital loss, debt restructuring charges and currently non-deductible interest carryforwards	$ 14,626	$ 12,911
Unrealized foreign exchange differences on US entity debt	15,109	10,800
Customer advances in aid of construction – difference between net book value and tax value	3,794	-
Total future tax assets	33,529	23,711
Less: Valuation allowance	(24,002)	(17,911)
	9,527	5,800
Future tax liabilities:		
Capital assets –differences between net book value and undepreciated capital cost	(43,495)	(23,861)
Intangible assets – difference between net book value and cumulative eligible capital	(15,678)	(23,427)
Customer advances in aid of construction – difference between net book value and tax value	-	(5,721)
Other	(1,124)	(755)
Total future tax liabilities	(60,297)	(53,764)
Net future tax liability	$ (50,770)	$ (47,964)
Classified in the financial statements as:		
Future current income tax asset	$ 18	$ 105
Future non-current income tax asset	6,425	6,809
Future current income tax liability	(1,449)	(866)
Future non-current income tax liability	(55,764)	(53,012)
	$ (50,770)	$ (46,964)

2003 includes a reduction in future non-current income tax liability of $11,671 due to Litchfield Park future income tax liability set up on acquisition in error.

At December 31, 2004, the Fund itself has financing expenses and underwriters' fees of $9,148 (2003 - $9,266) which will be deductible by the Fund and which will reduce the ultimate amount taxable to the unitholders over the next four years. This will be offset by additions to the unitholders' taxable income since the Fund's capital assets have an accounting basis that exceeds their tax basis by $6,643 (2003 - $5,095). In addition, two trusts wholly-owned by the Fund have capital assets with an accounting basis which exceeds their tax basis by $3,850 (2003 - $5,852).

13. Algonquin Power Group

(a) Management Agreement
APMI provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2004 and 2003, APMI was paid on a cost recovery basis for all costs incurred and charged $777 (2003-$710). APMI is also entitled to an incentive fee of 25% on all distributable cash generated in excess of $0.92 per trust unit. During 2004 and 2003 no incentive fees were earned by APMI.

(b) Operations
The Fund's power generating facilities have direct operations contracts with APS. The direct operations contracts provide for the day-to-day services required to operate and maintain the facilities in addition to planning of capital repairs, compliance monitoring for environmental permits and administration of power purchase agreements. In 2004 and 2003, APS was paid $12,823 (2003 - $11,386) on a cost recovery basis for all costs incurred.

(c) Water reclamation and distribution
The water reclamation and distribution facilities have direct operations contracts with AWS. The direct operations contracts provide for the day-to-day services required to operate and maintain the facilities. In 2004 and 2003, AWS was paid $4,883 (2003 - $5,176) on a cost recovery basis for all costs incurred.

(d) Other
During 2004, the Fund reimbursed APC $nil (2003 - $250) for legal fees paid by APC on behalf of the Fund to outside counsel.

14. Commitments and contingencies

(a) Land and Water Leases
Certain of the operating entities have entered into agreements to lease either the land and/or the water rights for the hydroelectric generating facility or to pay in lieu of property tax an amount based on electricity production. The terms of these leases continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. The Fund incurred $2,919 during 2004 (2003 - $2,865) in respect of these agreements for the consolidated facilities.

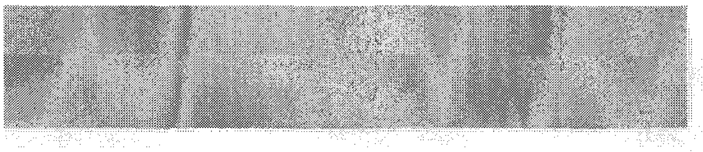
(b) Commitments and contingencies
The Fund has entered into a purchase and sale agreement to acquire eight water and wastewater systems from Silverleaf Resort, Inc. The systems, which in aggregate serve approximately 7,000 equivalent residential connections, are located in Texas, Missouri and Illinois. Closing of this transaction is anticipated to be mid-March, 2005. The total purchase price is estimated to be US $ 13,200, net of a refundable deposit of US $ 1,000, included in deferred charges at December 31, 2004.

The Fund and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider the Fund's exposure to such litigation to be material to these financial statements.

15. Fair value of financial instruments and derivatives

The carrying amount of the Fund's cash and cash equivalents, accounts receivable, funds held in reserve, accounts payable and accrued liabilities, due to Algonquin Power Group and cash distribution payable, approximate fair market value.

The carrying amount of the Fund's long-term investments is dependent on the underlying operations and accordingly a fair



value is not readily available. The Fund has long-term liabilities at fixed interest rates. The fair value of these long-term liabilities at current rates would be $121,931 (2003- $182,410). The fair value of other long-term liabilities approximates their carrying value, with the exception of the Joliet subsidy which is not readily available.

Deferred credits include payments made by developers to the Infrastructure Division of which a portion based on revenue for the development in question needs to be paid back over time. These amounts do not bear interest and the amount to be repaid is uncertain and fair value not determinable.

The Fund's cogeneration facility in Mahwah, New Jersey is currently paying market rates for its natural gas purchases since its contract expired in April, 2004. The facility had entered into price swap contracts to fix the price paid for a portion of the natural gas purchases for the facility. The contracts fixed the price of natural gas at U.S.$6.40 per mmbtu for 22,000 mmbtus per month from June, 2003 to April, 2004. Each month there was a settlement on the difference between the fixed price and the spot price based on the Texas Eastern M-3 price. There is no fair value of the contract at December 31, 2004 (2003 U.S. $2).

The Fund has entered into foreign exchange contracts to manage its exposure to the U.S. dollar as significant cash flows are generated in the U.S. The Fund sells specific amounts of currencies at predetermined dates and exchange rates that are matched with the anticipated operational cash flows. Contracts in place at December 31, 2004 include forward contracts of U.S.$98,812 until 2009 at a weighted average exchange rate of $1.4014. The fair value of the outstanding futures contracts is $16,600 at December 31, 2004 (2003 – $10,782).

16. Cash distributions

Distributable income, as defined in the Declaration of Trust, is distributed monthly. Distributions are declared to unitholders-of-record on the last day of the month and are distributed 45 days after declaration. The monthly distribution for 2004 was $0.0766 per trust unit for each month for a total of $0.92 for 2004, the same as 2003.

17. Basic and diluted net earnings per trust unit

Net earnings per trust unit has been calculated using the weighted average number of units outstanding during the year. The weighted average number of units outstanding for 2004 was 68,821,431 (2003 – 67,887,612). The net earnings per trust unit for 2004 was $0.33 (2003 - $0.66). The effect of conversion of the convertible debentures into trust units was not included in the computation of fully-diluted net earnings per trust unit as the effect of conversion would be anti-dilutive.

18. Segmented information

	2004	2003
Revenue		
Canada	$ 51,725	$ 45,629
United States	108,798	101,891
	$ 160,523	$ 147,520
Capital assets		
Canada	$ 319,445	$ 328,283
United States	291,311	282,097
	$ 610,756	$ 610,380
Intangible assets		
Canada	$ 27,262	$ 29,130
United States	56,415	53,204
	$ 83,677	$ 82,334

Revenues are attributable to the two countries based on the location of the underlying generating and infrastructure facilities.

Operational segments

The Fund identifies four business categories it operates in. The operations and assets for these segments are outlined below.

12 months ended December 31, 2004

	Hydro	Cogeneration	Alternative Fuels	Infrastructure	Admin	Total
Revenue						
Energy sales	43,268	71,846	7,867	-	-	122,981
Waste disposal fees	-	-	14,086	-	-	14,086
Water reclamation and distribution	-	-	-	23,456	-	23,456
Total Revenue	43,268	71,846	21,953	23,456	-	160,523
Operating expenses	17,442	50,597	15,124	10,849	-	94,012
Operating profit	25,826	21,249	6,829	12,607	-	66,511
Other administration costs	(137)	–	(152)	(84)	(3,882)	(4,255)
Interest expense	(5,177)	(772)	(355)	(1,135)	(5,001)	(12,440)
Interest, dividend and other income	557	4,024	1,352	9	739	6,681
Income from note receivable prepayment					3,634	3,634
Amortization of capital assets	(9,598)	(6,741)	(5,933)	(5,490)	-	(27,762)
Amortization of intangible assets	(1)	(2,849)	(3,112)	(503)	-	(6,465)
Earnings before income taxes and minority interest	11,470	14,911	(1,371)	5,404	(4,510)	25,904
Capital assets	285,860	90,868	94,562	139,466	-	610,756
Intangible assets	21	33,775	28,775	21,106	-	83,677
Capital expenditures (excl. acquisitions)	-	1,514	476	14,833	513	17,336
Intangible expenditures	-	-	-	-	-	-
Total assets	307,105	158,023	150,234	175,437	33,100	823,899

12 months ended December 31, 2003

	Hydro	Cogeneration	Alternative Fuels	Infrastructure	Admin	Total
Revenue						
Energy sales	44,413	61,890	6,423	-	-	112,726
Waste disposal fees	-	-	14,650	-	-	14,650
Water reclamation and distribution	-	-	-	20,237	-	20,237
Total Revenue	44,413	61,890	21,073	20,237	-	147,613
Operating expenses	15,862	42,758	12,895	9,165	-	80,680
Operating profit	28,551	19,132	8,178	11,072	-	66,933
Other administration costs	(277)	-	(128)	(81)	10,466	9,980
Interest expense	(5,224)	(666)	(290)	(2,283)	(3,168)	(11,631)
Interest, dividend and other income	494	4,641	1,150	45	278	6,608
Amortization of capital assets	(9,889)	(5,647)	(4,398)	(5,490)	-	(25,424)
Amortization of intangible assets	(346)	(2,489)	(2,024)	(91)	-	(4,950)
Earnings before income taxes and minority interest	13,309	14,971	2,488	3,172	7,576	41,516
Capital assets	289,317	96,616	90,753	133,694	-	610,380
Intangible assets	23	36,623	30,141	15,547	-	82,334
Capital expenditures	8	37,762	295	85,149	-	123,214
Intangible expenditures	-	12,395	-	14,919	-	27,314
Total assets	308,700	191,941	131,899	158,033	18,051	808,624

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2004 or 2003: Ontario Electricity Financial Corporation 10% (2003 – 10%); Hydro Québec 15% (2003-14%); Pacific Gas and Electric 15% (2003-18%); and Connecticut Light and Power 24% (2003-31%). The Fund has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

19. Joint venture investments

	Ownership Interest	Fund's Proportionate Share: Income Before Income Tax Year ended December 31		Net Assets December 31		Cash flow Generated from Operations ended December 31	
		2004	2003	2004	2003	2004	2003
Valley Power Limited Partnership	50%	$ 281	$ 173	$ 9,016	$ 8,912	$ 875	$ 741
Campbellford Limited Partnership	50%	277	188	3,729	3,921	511	422
		$ 558	$ 361	$12,745	$12,833	$ 1,386	$ 1,163

20. Guarantees

In the normal course of operations, the Fund executes agreements that provide letters of credit to third parties to secure certain amounts of indebtedness or performance. At December 31, 2004, letters of credit outstanding amounted to $26,705.

21. Restatement

Capital assets and the future income tax liability have been reduced $11,617 in 2003 to correct an error related to the determination of the tax basis of aid-in-construction payments on acquisition of certain infrastructure facilities. This restatement has no impact to net income or cash available for distribution to unitholders.

CORPORATE INFORMATION AND CONTACTS

Trustees
Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.
Christopher J. Ball - Executive Vice-President, Corpfinance International Limited
George Steeves – Principal, True North Energy (1169417 Ontario Inc.)

The Management Group
Algonquin Power Management Inc.
Chris K. Jarratt, Chief Executive Officer and Director
John M.H. Huxley, Director
Ian E. Robertson, Director
David C. Kerr, Director

Algonquin Power Income Fund
Peter Kampian,
Chief Financial Officer

Head Office
2845 Bristol Circle
Oakville, Ontario, L6H 7H7
Telephone: (905) 465-4500
Fax: (905) 465-4514
Email: apif@algonquinpower.com
Website: www.algonquinpower.com

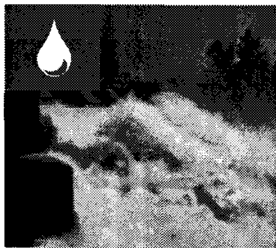
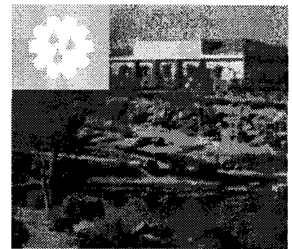
Registrar and Transfer Agent
CIBC Mellon Trust Company
320 Bay Street PO Box 1
Toronto, Ontario, M5H 4A6

Annual General Meeting
April 26, 2005, 4:00 p.m.
Blake, Cassels & Graydon LLP
199 Bay Street, Floor 23
Toronto, Ontario, M5L 1A9

Stock Exchange
The Toronto Stock Exchange: APF.UN

Auditors
KPMG LLP
Toronto, Ontario

Legal Counsel
Blake, Cassels & Graydon LLP
Toronto, Ontario

THE FUND OWNS AND OPERATES 300 MW GENERATING CAPACITY. ITS WATER RECLAMATION AND DISTRIBUTION ASSETS PROVIDE SERVICE TO 40,000 CONNECTIONS.

Year	Asset	Regions	Facilities	Capacity (MW)	Connections	Events
1997	Hydroelectric	4	14	19		Initial Public Offering, $80 Million
1998	Hydroelectric	5	29	69		Secondary Offering, $65 Million
1999	Hydroelectric	5	38	101		Secondary Offerings, $100 Million
2000	Hydroelectric	5	41	171		Secondary Offering, $28 Million
2001	Hydroelectric Cogeneration Alternative Fuels Infrastructure	6	47 Interest in 3 Interest in 3 2	141 288 66	4,500	Secondary Offerings, $235 Million
2002	Hydroelectric Cogeneration Alternative Fuels Infrastructure	6	47 Interest in 3 Own/Operate 2 Interest in 3 Own/Operate 2 5	141 288 54 66 13	13,500	Secondary Offerings, $171 Million
2003	Hydroelectric Cogeneration Alternative Fuels Infrastructure	6	47 Interest in 3 Own/Operate 3 Interest in 3 Own/Operate 2 6	141 288 110 66 13	36,800	
2004	Hydroelectric Cogeneration Alternative Fuels Infrastructure	6	47 Interest in 2 Own/Operate 3 Interest in 4 Own/Operate 14 6	141 138 110 166 49	40,000	Convertible Debenture Offering, $85 Million

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STABILITY PERFORMANCE OPPORTUNITY

ATTACHMENT B

As usual, the Water Utility Industry ranks near the bottom of the *Value Line Investment Survey* for Timeliness. Earnings for the companies in this industry continued to lag those of most industrial companies in 2005, reflecting the effects of rainy weather and rising infrastructure costs. Although recent changes in the makeup of regulatory bodies and improved weather conditions paint a more favorable backdrop, we still have some concerns about the industry's earnings potential going forward. At the heart of our concerns are the rapidly increasing infrastructure costs. With that in mind, not one of the water utility stocks that are covered in the next few pages offers decent capital-gains appeal.

Nevertheless, a few of the stocks here may be of interest to those looking for current income.

Regulating The Industry

Regulatory authorities were appointed to keep a balance of power between consumers and providers. However, water utility providers have been coming out on the short end of the stick in recent years. Indeed, rate relief case decisions have been put on the back burner (and long-awaited outcomes have generally been unfavorable.) However, there appears to be a better story unfolding for water utilities, particularly those with operations in the state of California. With urging from Governor Schwarzenegger, the California Public Utilities Commission (CPUC), which is responsible for ruling on general rate case requests in the Golden State, things appear to have reversed course. Members of the board thought to be antagonists of rate relief have been replaced with more-business-friendly members. And, the changes appear to already be paying off. Case decisions have been coming in with more favorable decisions in recent months, auguring well for the future business of *American States Water Co.* and *California Water Service Group.*

Expenses

Despite these changes, already stringent regulatory laws on pipeline and well infrastructure are likely to increase as we head forward. Much of the current infrastructure is more than 100 years old and is in desperate need of maintenance and, in some cases, massive renovations and rebuilding. Making matters worse, is the heightened threat of bioterrorism on U.S. water pipelines and reservoirs. These costs are likely to continue to rise, as companies strive to comply with EPA water purification standards. In all, infrastructure repair costs are expected to climb to the hundreds of millions of dollars over the next two decades, putting many smaller water companies at a distinct disadvantage. In fact, many companies without the capital to pay for these initiatives are being forced to sell, resulting in massive consolidation within the industry. As a result, the rich have been getting richer. Larger, more flexible companies with the money to meet the higher costs have been using the weakness to add to their customer base. *Aqua America*, the largest water utility in our Survey, is the prime example. It has made nearly 100 acquisitions over the past five years, doubling its revenue base during that time. And, with no end to its aggressive buying in sight, we think that *Aqua* will continue to deliver the highest return on equity of any of the companies in this industry.

INDUSTRY TIMELINESS: 81 (of 98)

Investment Advice

The stocks in this industry do not stand out for their capital-gains potential. Not a single one of the issues here is ranked above 3 (Average) for Timeliness and none hold better than modest 3- to 5- year appreciation potential. Despite the necessity for water, the capital-intensive nature of the industry strips away growth appeal. As a result, we think that growth-oriented investors will want to take a pass and look elsewhere.

However, we believe that income-minded investors may have a somewhat different point of view. Water utility stocks have long generated a steady stream of income, a trend that we do not envision changing anytime soon. In fact, *American States Water* and *California Water* both offer above-average dividend yields and, according to our projections, should continue to do so over the long haul. Even still, there may be better income vehicles available to investors at this time. *California Water* offers some additional appeal, though, given its Above Average (2) Safety rank. As is always the case, though, we recommend that potential investors take a careful look at the individual reports on the following pages before making any future financial commitments.

Andre J. Costanza

Composite Statistics: Water Utility Industry

2001	2002	2003	2004	2005	2006		08-10
751.8	794.4	857.0	985.6	*1250*	*1350*	Revenues ($mill)	*1750*
95.4	106.6	98.6	122.4	*155*	*170*	Net Profit ($mill)	*250*
40.2%	38.8%	40.0%	39.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
--	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
52.4%	53.9%	51.2%	50.0%	*52.0%*	*51.0%*	Long-Term Debt Ratio	*48.0%*
47.2%	45.9%	48.6%	50.0%	*48.0%*	*49.0%*	Common Equity Ratio	*52.0%*
1840.7	1973.6	2296.4	2543.6	*3000*	*3500*	Total Capital ($mill)	*4475*
2532.2	2751.1	3186.1	3532.5	*4000*	*4125*	Net Plant ($mill)	*5850*
6.8%	7.0%	5.9%	6.7%	*7.0%*	*7.5%*	Return on Total Cap'l	*7.0%*
10.6%	11.2%	8.8%	10.7%	*11.0%*	*10.0%*	Return on Shr. Equity	*11.0%*
10.7%	11.2%	8.8%	10.7%	*11.0%*	*10.0%*	Return on Com Equity	*11.0%*
3.3%	3.8%	2.5%	4.6%	*5.0%*	*5.0%*	Retained to Com Eq	*3.0%*
69%	66%	72%	57%	*60%*	*55%*	All Div'ds to Net Prof	*45%*
22.6	21.5	26.0	25.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
1.16	1.17	1.48	1.36			Relative P/E Ratio	*1.20*
3.1%	3.1%	2.8%	2.2%			Avg Ann'l Div'd Yield	*3.4%*

Water Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)

AMER. STATES WATER NYSE-AWR

RECENT PRICE 31.60 | P/E RATIO 24.3 (Trailing: 29.8 Median: 16.0) | RELATIVE P/E RATIO 1.29 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Raised 11/7/03
SAFETY 3 New 2/4/00
TECHNICAL 3 Lowered 11/18/05
BETA .75 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	14.7	14.0	16.1	17.1	19.5	26.5	25.3	26.4	29.0	29.0	26.8	34.6
Low:	10.2	10.5	12.5	13.5	14.1	14.8	16.7	19.0	20.3	21.6	20.8	24.3

Target Price Range 2008 2009 2010

2008-10 PROJECTIONS

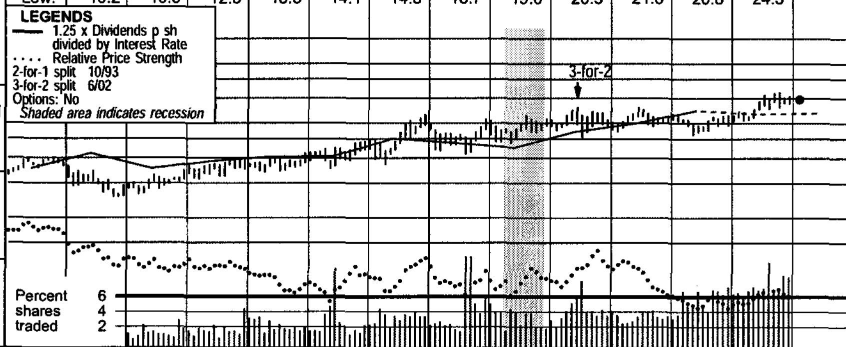
	Price	Gain	Ann'l Total Return
High	35	(+10%)	5%
Low	20	(-35%)	-7%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	43	42	54
to Sell	36	41	33
Hld's(000)	6278	6199	6302



% TOT. RETURN 12/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	22.3	6.8
3 yr.	46.6	85.4
5 yr.	48.5	70.4

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
9.12	9.58	9.15	10.10	9.27	10.43	11.03	11.37	11.44	11.02	12.91	12.17	13.06	13.78	13.98	13.60	13.75	14.75	Revenues per sh	16.00
1.44	1.49	1.78	1.81	1.67	1.68	1.75	1.75	1.85	2.04	2.26	2.20	2.53	2.54	2.08	2.22	2.45	2.85	"Cash Flow" per sh	3.70
.92	.94	1.19	1.15	1.11	.95	1.03	1.13	1.04	1.08	1.19	1.28	1.35	1.34	.78	1.05	1.10	1.45	Earnings per sh A	2.10
.69	.72	.73	.77	.79	.80	.81	.82	.83	.84	.85	.86	.87	.87	.88	.89	.90	.91	Div'd Decl'd per sh B■	.96
2.46	2.53	2.77	2.31	1.90	2.43	2.19	2.40	2.58	3.11	4.30	3.03	3.18	2.68	3.76	5.02	4.15	4.00	Cap'l Spending per sh	5.50
7.31	7.54	8.39	8.85	9.95	10.07	10.29	11.01	11.24	11.48	11.82	12.74	13.22	14.05	13.97	14.98	16.00	17.05	Book Value per sh	17.65
9.39	9.43	9.91	9.96	11.71	11.77	11.77	13.33	13.44	13.44	13.44	15.12	15.12	15.18	15.21	16.77	17.10	17.60	Common Shs Outst'g C	20.00
9.7	10.2	8.8	10.6	13.4	12.8	11.6	12.6	14.5	15.5	17.1	15.9	16.7	18.3	31.9	23.2	26.3		Avg Ann'l P/E Ratio	13.0
.73	.76	.56	.64	.79	.84	.78	.79	.84	.81	.97	1.03	.86	1.00	1.82	1.23	1.38		Relative P/E Ratio	.85
7.7%	7.5%	7.0%	6.3%	5.3%	6.6%	6.7%	5.8%	5.5%	5.0%	4.2%	4.2%	3.9%	3.6%	3.5%	3.7%	3.1%		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/05
Total Debt $284.4 mill. Due in 5 Yrs $65.0 mill.
LT Debt $228.7 mill. LT Interest $19.5 mill.
(Total interest coverage: 3.1x)

Leases, Uncapitalized: None
Pension Assets-12/04 $51.3 mill.
Oblig. $70.3 mill.
Pfd Stock None. Pfd Div'd None.

Common Stock 16,789,533 shs.
as of 11/9/05
MARKET CAP: $525 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
129.8	151.5	153.8	148.1	173.4	184.0	197.5	209.2	212.7	228.0	235	260	Revenues ($mill)	320
12.2	13.5	14.1	14.6	16.1	18.0	20.4	20.3	11.9	16.4	20.0	26.0	Net Profit ($mill)	42.0
41.9%	43.3%	41.1%	40.9%	46.0%	45.7%	43.0%	38.9%	43.5%	37.7%	46.0%	43.0%	Income Tax Rate	42.0%
--	--	--	--	--	--	--	--	--	--	Nil	Nil	AFUDC % to Net Profit	Nil
46.6%	41.9%	43.0%	43.6%	51.0%	47.5%	54.9%	52.0%	52.0%	47.7%	48.0%	50.0%	Long-Term Debt Ratio	52.0%
52.5%	57.3%	56.3%	55.7%	48.4%	51.9%	44.7%	48.0%	48.0%	52.3%	52.0%	50.0%	Common Equity Ratio	48.0%
230.6	256.0	268.4	277.1	328.2	371.1	447.6	444.4	442.3	480.4	525	600	Total Capital ($mill)	735
335.0	357.8	383.6	414.8	449.6	509.1	539.8	563.3	602.3	664.2	715	785	Net Plant ($mill)	925
7.2%	6.9%	6.9%	7.0%	6.6%	6.4%	6.1%	6.5%	4.6%	4.9%	5.5%	6.0%	Return on Total Cap'l	7.5%
9.9%	9.0%	9.2%	9.4%	10.0%	9.2%	10.1%	9.5%	5.6%	6.5%	7.5%	8.5%	Rurn on Shr. Equity	12.0%
10.0%	9.0%	9.2%	9.4%	10.1%	9.3%	10.1%	9.5%	5.6%	6.5%	7.5%	8.5%	Return on Com Equity	12.0%
2.1%	2.4%	1.8%	2.1%	2.9%	3.0%	3.6%	3.3%	NMF	NMF	1.5%	3.5%	Retained to Com Eq	6.5%
79%	73%	80%	78%	72%	68%	65%	65%	113%	91%	77%	62%	All Div'ds to Net Prof	46%

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	12.8	4.3	5.7
Receivables	11.8	14.3	15.2
Inventory (Avg Cst)	1.4	1.5	1.4
Other	32.4	32.9	34.2
Current Assets	58.4	53.0	56.5
Accts Payable	18.8	18.2	18.5
Debt Due	56.8	45.9	55.7
Other	20.3	22.2	29.7
Current Liab.	95.90	86.3	103.9
Fix. Chg. Cov.	237%	246%	250%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	3.5%	4.0%	2.5%
"Cash Flow"	3.0%	5.0%	8.5%
Earnings	--	1.5%	12.0%
Dividends	1.5%	1.0%	1.5%
Book Value	4.5%	4.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	44.5	52.8	61.6	50.3	209.2
2003	46.7	51.8	63.7	50.5	212.7
2004	46.7	59.3	69.0	53.0	228.0
2005	49.8	60.5	68.1	56.6	235
2006	55.0	67.0	76.0	62.0	260

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	.25	.36	.50	.23	1.34
2003	.20	.19	.51	d.12	.78
2004	.08	.30	.52	.16	1.05
2005	.09	.34	.47	.20	1.10
2006	.24	.39	.58	.24	1.45

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.217	.217	.217	.221	.87
2003	.221	.221	.221	.221	.88
2004	.221	.221	.221	.225	.89
2005	.225	.225	.225	.225	.90
2006					

BUSINESS: *American States Water Co. operates as a holding company. Through its principal subsidiary, Golden State Water Company, it supplies water to 75 communities in 10 counties. Service areas include the greater metropolitan areas of Los Angeles and Orange Counties. The company also provides electric utility services to approximately 22,000 customers in the city of Big Bear Lake and in areas of San Bernardino County. Acquired Chaparral City Water of Arizona (10/00); 11,400 customers. Has roughly 525 employees. Off. & dir. own 2.4% of common stock (4/05 Proxy). Chairman: Lloyd Ross. President & CEO: Floyd Wicks. Incorporated: CA. Add.: 630 East Foothill Boulevard, San Dimas, CA 91773. Tel.: 909-394-3600. Web: www.aswater.com.*

Unfavorable weather conditions have continued to be a problem for American States Water. It reported third-quarter share earnings of $0.47 (excluding a $0.25 one-time gain in association with the recent Aerojet settlement), a nickel below the year-ago figure. Billed water consumption decreased approximately 3% owing to persistingly wet conditions in the Golden State. Earnings were also negatively impacted by a higher tax rate during the quarter.

Still, American probably rebounded in the fourth quarter. Fourth-quarter weather conditions looked to be more favorable, which should generate an improved top-line comparison. As a result, we think that American probably posted a solid earnings gain.

2006 should be a banner year. The California Public Utilities Commission (CPUC), which oversees all local utilities, has undergone a major restructuring of late, providing a far more favorable regulatory backdrop than that of recent memory. Indeed, recent decisions signal that the regulatory climate is improving, and that rulings are becoming more business friendly. For instance, the CPUC has approved rate increases for Region II and Region I customer service areas of its GSWC unit effective January 1, 2006. The rate hikes add more than $5.6 million in annual revenues. More importantly, the favorable decision augurs well for future case decisions.

Nevertheless, these untimely shares hold limited capital gains appeal. Despite the improving regulatory landscape, capital constraints limit 3- to 5-year growth potential. American, which is already low on cash, will be forced to make additional equity and debt offerings in order to keep up with escalating infrastructure costs. We are concerned that these moves will not only dilute earnings, but may even prevent AWR from taking advantage of the fragmented industry and enhancing its business model.

The stock does offer an above-average dividend yield and some investors may find solace in the fact that AWR has increased its annual dividend for 51 consecutive years. However, still higher yields are now available from bonds or CDs.

Andre J. Costanza *January 27, 2006*

(A) Primary earnings. Excludes nonrecurring gains: '91, 73¢; '92, 13¢; '04, 14¢; '05, 52¢. Quarterly earnings may not sum due to change in share count. Next earnings report due early Feb.
(B) Dividends historically paid in early March, June, September, December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	80
Earnings Predictability	65

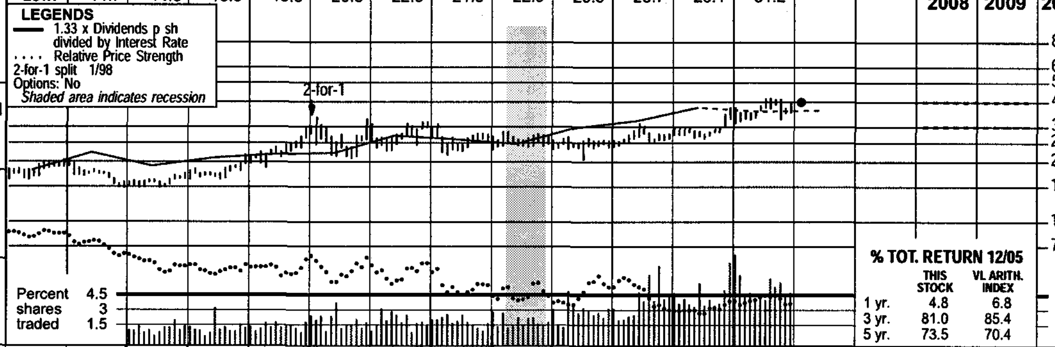
CALIFORNIA WATER NYSE-CWT

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
39.96	22.8	(Trailing: 29.6 Median: 19.0)	1.21	2.9%	VALUE LINE

TIMELINESS 4 Raised 11/4/05
SAFETY 2 Lowered 8/11/95
TECHNICAL 3 Lowered 9/9/05
BETA .75 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	20.5	17.6	21.9	29.6	33.8	32.0	31.4	28.6	26.9	31.4	37.9	42.1
Low:	14.7	14.8	16.3	18.6	20.8	22.6	21.5	22.9	20.5	23.7	26.1	31.2

Target Price Range
2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(Nil)	3%
Low	30	(-25%)	-3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	0	0	5	2	0	0
to Sell	0	0	0	1	0	5	2	0	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	35	48	38
to Sell	37	24	39
Hld's(000)	4613	4744	4897

% TOT. RETURN 12/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	4.8	6.8
3 yr.	81.0	85.4
5 yr.	73.5	70.4

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
10.33	10.93	11.18	12.29	13.34	12.59	13.17	14.48	15.48	14.76	15.96	16.16	16.26	17.33	16.37	17.18	*17.30*	*18.70*	Revenues per sh	*21.75*
1.89	1.97	1.98	1.92	2.25	2.02	2.07	2.50	2.92	2.60	2.75	2.52	2.20	2.65	2.51	2.84	*3.00*	*3.30*	"Cash Flow" per sh	*4.10*
1.20	1.25	1.21	1.09	1.35	1.22	1.17	1.51	1.83	1.45	1.53	1.31	.94	1.25	1.21	1.46	*1.45*	*1.70*	Earnings per sh A	*2.15*
.84	.87	.90	.93	.96	.99	1.02	1.04	1.06	1.07	1.09	1.10	1.12	1.12	1.12	1.13	1.14	*1.15*	Div'd Decl'd per sh B ■	*1.24*
2.40	2.36	3.03	3.09	2.53	2.26	2.17	2.83	2.61	2.74	3.44	2.45	4.09	5.82	4.39	3.73	*4.10*	*4.00*	Cap'l Spending per sh	*4.15*
9.66	10.04	10.35	10.51	10.90	11.56	11.72	12.22	13.00	13.38	13.43	12.90	12.95	13.12	14.44	15.65	*16.70*	*17.25*	Book Value per sh C	*19.55*
11.38	11.38	11.38	11.38	11.38	12.49	12.54	12.62	12.62	12.62	12.94	15.15	15.18	15.18	16.93	18.37	*18.50*	*19.00*	Common Shs Outst'g D	*23.00*
10.6	10.4	11.2	14.1	13.6	14.1	13.7	11.9	12.6	17.8	17.8	19.6	27.1	19.8	22.1	20.1	*24.5*		Avg Ann'l P/E Ratio	*16.0*
.80	.77	.72	.86	.80	.92	.92	.75	.73	.93	1.01	1.27	1.39	1.08	1.26	1.06	*1.29*		Relative P/E Ratio	*1.05*
6.6%	6.7%	6.6%	6.1%	5.2%	5.8%	6.4%	5.8%	4.6%	4.2%	4.0%	4.3%	4.4%	4.5%	4.2%	5.0%	3.1%		Avg Ann'l Div'd Yield	*3.5%*
						165.1	182.8	195.3	186.3	206.4	244.8	246.8	263.2	277.1	315.6	*320*	*355*	Revenues ($mill)	*500*
						14.7	19.1	23.3	18.4	19.9	20.0	14.4	19.1	19.4	26.0	*27.0*	*33.0*	Net Profit ($mill)	*50.0*
						40.1%	38.9%	37.4%	36.4%	37.9%	42.3%	39.4%	39.7%	39.9%	39.6%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
						--	--	--	--	--	--	--	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
						49.2%	47.4%	45.4%	44.2%	46.9%	48.9%	50.3%	55.3%	50.2%	48.6%	*48.5%*	*49.0%*	Long-Term Debt Ratio	*49.5%*
						49.7%	51.4%	53.5%	54.7%	52.0%	50.2%	48.8%	44.0%	49.1%	50.8%	*51.0%*	*50.5%*	Common Equity Ratio	*50.0%*
						296.0	299.9	306.7	308.6	333.8	388.8	402.7	453.1	498.4	565.9	*605*	*650*	Total Capital ($mill)	*900*
						422.2	443.6	460.4	478.3	515.4	582.0	624.3	697.0	759.5	800.3	*870*	*950*	Net Plant ($mill)	*1100*
						6.8%	8.3%	9.4%	7.8%	7.8%	6.8%	5.3%	5.9%	5.6%	6.1%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.5%*
						9.8%	12.1%	13.9%	10.7%	11.2%	10.0%	7.2%	9.4%	7.8%	8.9%	*8.5%*	*10.0%*	Return on Shr. Equity	*11.0%*
						9.9%	12.3%	14.1%	10.8%	11.4%	10.1%	7.2%	9.5%	7.9%	9.0%	*9.0%*	*10.0%*	Return on Com Equity	*11.0%*
						1.2%	3.8%	6.0%	2.8%	3.5%	1.8%	NMF	1.0%	.7%	1.8%	*1.5%*	*3.5%*	Retained to Com Eq	*5.0%*
						88%	69%	58%	74%	70%	82%	119%	90%	91%	80%	*78%*	*65%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 9/30/05
Total Debt $275.5 mill. **Due in 5 Yrs** $11.0 mill.
LT Debt $274.4 mill. **LT Interest** $18.0 mill.

(LT interest earned: 3.8x; *total int. cov.: 3.4x*)

Pension Assets-12/04 $75.1 mill.
Oblig. $87.6 mill.
Pfd Stock $3.5 mill. **Pfd Div'd** $.15 mill.
139,000 shares, 4.4% cumulative ($25 par).

Common Stock 18,389,996 shs.
as of 11/1/05
MARKET CAP: $750 million (Small Cap)

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	2.9	18.8	23.8
Other	40.6	51.6	51.6
Current Assets	43.5	70.4	75.4
Accts Payable	23.8	19.8	29.5
Debt Due	7.3	--	1.1
Other	32.5	36.4	50.5
Current Liab.	63.6	57.2	82.1
Fix. Chg. Cov.	218%	309%	*325%*

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	3.0%	2.0%	*4.0%*
"Cash Flow"	2.0%	-1.5%	*7.5%*
Earnings	-0.5%	-6.5%	*8.5%*
Dividends	2.0%	1.0%	*1.5%*
Book Value	2.5%	1.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	51.7	69.2	81.4	60.9	263.2
2003	51.3	68.0	88.2	69.6	277.1
2004	60.2	88.9	97.1	69.4	315.6
2005	60.3	81.5	101.1	*77.1*	*320*
2006	*65.0*	*95.0*	*110*	*85.0*	*355*

Cal-endar	EARNINGS PER SHARE A E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.12	.43	.50	.20	1.25
2003	d.05	.30	.53	.41	1.21
2004	.08	.59	.59	.20	1.46
2005	.03	.41	.71	*.30*	*1.45*
2006	*.12*	*.62*	*.67*	*.29*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.28	.28	.28	.28	1.12
2003	.281	.281	.281	.281	1.12
2004	.283	.283	.283	.283	1.13
2005	.285	.285	.285	.285	1.14
2006					

BUSINESS: California Water Service Group provides regulated and nonregulated water service to over 2 million people (451,800 customers) in 75 communities in California, Washington, and New Mexico. *Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles.* Acquired National Utility Company (5/04); Rio Grande Corp. (11/00). Revenue breakdown, '04: residential, 70%; business, 18%; public authorities, 5%; industrial, 4%; other, 3%. '04 reported deprec. rate: 2.3%. Has about 837 employees. Chairman: Robert W. Foy. President & CEO: Peter C. Nelson. Inc.: Delaware. Address: 1720 North First Street, San Jose, California 95112-4598. Telephone: 408-367-8200. Internet: www.calwater.com.

California Water Service group is already reaping the benefits of changes at the California Public Utilities Commission (CPUC) . . . The company has had to deal with sluggish and unfavorable rate case rulings in recent years. However, the CPUC, which is in charge of supervising all local utilities, has undergone a number of changes in personnel and, behind the urging of Governor Schwarzenegger, appears to have instituted a more business-friendly demeanor. In fact, CWT, despite poor weather conditions, posted third-quarter earnings of $0.71 a share, well above both last year's figure as well as our estimate.

. . . and should continue to do so going forward. The improving regulatory environment, coupled with better weather conditions paints an auspicious backdrop for CWT. It enjoyed rate case success in 2005 and should continue to do so in 2006 and thereafter. The company filed a general rate case increase for eight districts, representing roughly a quarter of its customer base, in August, requesting about $11 million in 2006 and $6 million in 2007. Although the CPUC probably will not grant the full amount, we anticipate a favorable ruling nonetheless. In all, we look for CWT to grow earnings by 15% to 20% in 2006.

However, capital constraints are cause for concern. The costs of maintaining well and pipeline infrastructure are on a torrid pace and, with concerns of bioterrorism on the rise, do not appear as though they will be subsiding *anytime soon*. As a result, CWT will need to tap equity and debt markets to foot the bill. Although necessary, this additional financing would dilute earnings, resulting in moderating share-net growth out to late decade. Accordingly, given our current projections, these shares are already near the top of our 3- to 5-year Target Price Range and offer minimal capital appreciation potential.

CWT is a relatively safe choice for those looking to add an income component to their portfolios. The company *should continue* to provide investor with a steady stream of income and maintain its above-average yield going forward. CWT is ranked 2 (Above Average) for Safety.

Andre J. Costanza *January 27, 2006*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (7¢); '01, 4¢; 02, 8¢. Next earnings report due late April.
(B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. deferred charges. In '04: $54.3 mill., $2.96/sh.
(D) In millions, adjusted for split.
(E) May not total due to change in shares.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	90
Earnings Predictability	65

SOUTHWEST WATER NDQ-SWWC

RECENT PRICE	15.05	P/E RATIO	37.6 (Trailing: 58.6 / Median: 18.0)	RELATIVE P/E RATIO	2.00	DIV'D YLD	1.5%	VALUE LINE

TIMELINESS **3** New 10/28/05
SAFETY **3** New 10/28/05
TECHNICAL **2** Lowered 1/27/06
BETA .70 (1.00 = Market)

High:	2.4	2.1	3.7	5.0	5.6	9.2	8.3	10.2	12.4	11.2	14.3	15.2				Target Price Range
Low:	1.5	1.5	2.0	2.6	3.5	3.6	5.1	6.9	7.6	8.1	10.3	9.0		2008	2009	2010

2008-10 PROJECTIONS

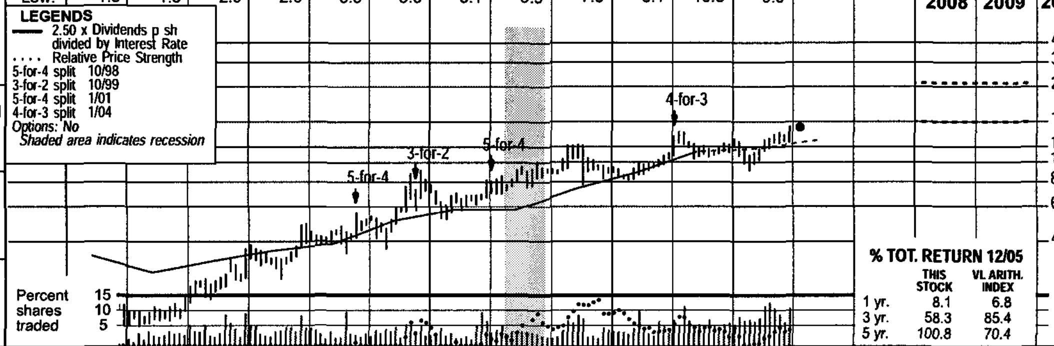
	Price	Gain	Ann'l Total Return
High	25	(+65%)	15%
Low	16	(+5%)	3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	1	2	0	0	0	0	0	0
Options	0	2	0	0	0	3	1	1	1
to Sell	0	1	0	0	0	1	2	1	1

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	32	28	39
to Sell	23	16	15
Hld's(000)	4896	5044	5706



% TOT. RETURN 12/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.1	6.8
3 yr.	58.3	85.4
5 yr.	100.8	70.4

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
3.49	3.76	3.51	3.96	4.23	4.41	5.08	5.58	5.89	5.91	6.47	7.86	8.56	9.57	11.23	9.69	9.50	10.50	Revenues per sh	12.80
.46	.48	.29	.46	.40	.40	.46	.49	.56	.62	.69	.80	.91	.90	.96	.71	.85	1.00	"Cash Flow" per sh	1.65
.25	.23	.02	.20	.08	.09	.12	.16	.22	.27	.32	.40	.44	.41	.47	.24	.35	.45	Earnings per sh A	.95
.18	.19	.19	.19	.14	.08	.08	.09	.10	.10	.11	.14	.15	.16	.17	.19	.20	.22	Div'd Decl'd per sh B	.29
.42	.53	.41	.44	.63	.75	.88	.99	.78	.83	.55	.58	1.11	1.87	1.19	1.33	1.20	1.20	Cap'l Spending per sh	1.40
2.59	2.70	2.53	2.54	2.42	2.42	2.57	2.52	2.65	2.83	3.20	3.61	4.03	4.49	5.14	6.48	6.55	6.80	Book Value per sh D	8.80
10.82	10.93	11.05	11.24	11.40	11.55	11.18	11.86	12.05	12.21	12.50	13.33	13.50	13.66	15.40	19.40	20.50	20.50	Common Shs Outst'g C	21.50
12.8	14.2	NMF	14.5	35.8	22.3	14.6	16.6	16.9	17.2	19.6	17.0	19.8	24.8	21.2	NMF	34.5		Avg Ann'l P/E Ratio	21.0
.97	1.05	NMF	.88	2.11	1.46	.98	1.04	.97	.89	1.12	1.11	1.01	1.35	1.21	NMF	1.80		Relative P/E Ratio	1.40
5.8%	5.7%	5.5%	6.6%	4.7%	4.2%	4.7%	3.4%	2.7%	2.3%	1.8%	2.0%	1.7%	1.5%	1.7%	1.5%	1.7%		Avg Ann'l Div'd Yield	1.5%

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
56.8	66.2	71.0	72.2	80.9	104.7	115.5	130.8	173.0	188.0	195	215	Revenues ($mill)	275
1.4	1.9	2.6	3.4	4.2	5.4	6.2	6.0	7.2	4.5	7.0	9.0	Net Profit ($mill)	21.0
39.0%	41.8%	41.6%	39.5%	39.0%	37.0%	36.0%	34.9%	35.9%	36.1%	36.0%	36.0%	Income Tax Rate	36.0%
--	--	--	--	--	--	14.4%	3.2%	--	11.0%	8.5%	8.0%	AFUDC % to Net Profit	5.0%
40.1%	50.2%	47.9%	48.7%	45.2%	48.8%	51.4%	56.7%	47.9%	47.9%	50.0%	50.0%	Long-Term Debt Ratio	46.0%
58.8%	48.9%	51.3%	50.5%	54.1%	50.7%	48.2%	42.9%	51.8%	52.0%	50.0%	50.0%	Common Equity Ratio	54.0%
48.9	61.1	62.2	68.5	73.9	95.0	113.0	142.8	152.8	242.0	265	280	Total Capital ($mill)	360
80.3	91.4	102.1	109.2	113.7	157.8	171.1	203.9	219.5	302.6	350	405	Net Plant ($mill)	630
5.3%	5.5%	6.8%	7.1%	7.6%	7.6%	7.6%	5.8%	6.2%	3.1%	4.0%	4.5%	Return on Total Cap'l	7.0%
4.9%	6.3%	8.0%	9.5%	10.3%	11.1%	11.4%	9.7%	9.0%	3.6%	5.0%	6.5%	Return on Shr. Equity	11.0%
4.9%	6.3%	8.1%	9.6%	10.4%	11.1%	11.4%	9.7%	9.1%	3.6%	5.0%	6.5%	Return on Com Equity	11.0%
1.5%	2.9%	4.5%	6.0%	7.0%	7.8%	7.8%	6.3%	5.8%	.8%	2.0%	3.0%	Retained to Com Eq	8.0%
69%	55%	45%	38%	33%	31%	32%	36%	36%	78%	57%	44%	All Div'ds to Net Prof	29%

CAPITAL STRUCTURE as of 9/30/05
Total Debt $126.2 mill. **Due in 5 Yrs** $45.0 mill.
LT Debt $124.9 mill. **LT Interest** $7.0 mill.
(Total interest coverage: 3.7x) (48% of Cap'l)

Leases, Uncapitalized: Annual rentals $6.2 mill.
Pension Liability None

Pfd Stock $500,000 **Pfd Div'd** $24,000

Common Stock 20,502,370 shs.
as of 11/7/05
MARKET CAP: $300 million (Small Cap)

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	5.4	1.9	6.8
Receivables	19.8	23.9	28.1
Inventory (Avg Cst)	--	1.9	--
Other	10.2	17.6	12.7
Current Assets	35.4	45.3	47.6
Accts Payable	11.4	12.3	11.3
Debt Due	2.7	3.4	1.3
Other	17.3	20.0	23.2
Current Liab.	31.4	35.7	35.8

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	9.0%	11.0%	4.0%
"Cash Flow"	7.5%	6.5%	11.5%
Earnings	11.5%	7.0%	17.0%
Dividends	2.0%	10.5%	9.0%
Book Value	8.0%	13.0%	8.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	28.2	32.7	34.6	35.3	130.8
2003	36.1	41.5	51.4	44.0	173.0
2004	39.8	45.7	55.0	47.5	188.0
2005	46.9	51.3	54.7	42.1	195
2006	50.0	55.0	60.0	50.0	215

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2002	.04	.11	.13	.13	.41
2003	d.01	.14	.22	.12	.47
2004	--	.14	.12	d.02	.24
2005	d.01	.15	.14	.07	.35
2006	.02	.17	.16	.10	.45

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.038	.038	.038	.038	.15
2003	.042	.042	.042	.046	.17
2004	.046	.046	.046	.05	.19
2005	.05	.05	.05	.05	.20
2006	.055				

BUSINESS: Southwest Water Company provides a broad range of services including water production, treatment and distribution; wastewater collection and treatment; utility billing and collection; utility infrastructure construction management; and public works services. It operates out of two groups, Utility (37% of 2004 revenues) and Services (63%). Utility owns and manages rate-regulated public water utilities in California, New Mexico, Oklahoma, and Texas. Services does mostly maintenance work on a contract basis. Off. & dir. own 10.0% of com. shs.; T. Rowe Price, 7.1% (4/05 proxy). Chrmn & CEO: Anton C. Garnier. Inc.: DE. Addr.: One Wilshire Building, 624 S. Gramd Avemie. Ste. 2900, Los Angeles, CA 90017. Tel.: 213-929-1800. Internet: www.southwestwater.com.

Southwest Water Company had a decent third quarter. Revenues during the September interim were little changed year-to-year, but share earnings showed a 17% improvement. The solid showing was punctuated with announcements for a 10% cash dividend increase and a 5% stock dividend payout (paid on January 20th). Also of note, the company has begun the search for a successor CEO, since current CEO and Chairman Anton Garnier announced he will be stepping down after 38 years of service with Southwest.

Recent appointments to the California Public Utilities Commission (CPUC) augurs well for Southwest. Governor Schwarzenegger has selected two candidates to fill vacant spots on the five-person CPUC committee. Both of the nominees are likely to take a more business-friendly approach towards regulatory matters than their predecessors, which should make for easier rate case wins in the coming years. Additionally, the CPUC will likely soon experience some restructuring changes, including combining the water and energy divisions at the staff level to increase efficiency. This may also work towards Southwest's benefit, but likely not until 2007 when the framework is finalized.

The first major rate case with the new CPUC was recently filed. Southwest just filed for an $8.6 million rate increase in California. A generally favorable outcome for the company in this case, as well as pending rate relief in Texas, should bolster earnings growth prospects in the coming years.

The acquisition of an Alabama wastewater system looks promising. During September, Southwest purchased the Shelby County, Alabama wastewater system for $8.5 million. The system reaches 4,400 customers and isn't regulated by a state agency, which should help boost margins. Additionally, long-term income from the acquisition seems insured as SWWC was able to secure 11 years of automatic 8% rate increases in the region.

Our projections show total-return potential for the years out to 2008–2010 to be slightly below average, based on the stock's current quotation.

Praneeth Satish *January 27, 2006*

(A) Diluted earnings. Excludes nonrecurring gains (losses): '00, (3¢); '01, (5¢); '02, 1¢; '05, (23¢). Next earnings report due early February.
(B) Dividends historically paid in late January, April, July, and October.
(C) In millions, adjusted for splits.
(D) Includes intangibles. In 2004: $29.2 million, $1.62/share.

Company's Financial Strength	B
Stock's Price Stability	80
Price Growth Persistence	90
Earnings Predictability	60

AQUA AMERICA NYSE-WTR

RECENT PRICE **27.65** | P/E RATIO **36.9** (Trailing: 38.3; Median: 21.0) | RELATIVE P/E RATIO **1.96** | DIV'D YLD **1.6%** | VALUE LINE

TIMELINESS	3	Raised 4/29/05	
SAFETY	3	Lowered 8/1/03	
TECHNICAL	2	Raised 1/13/06	

BETA .80 (1.00 = Market)

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+25%)	7%
Low	20	(-30%)	-6%

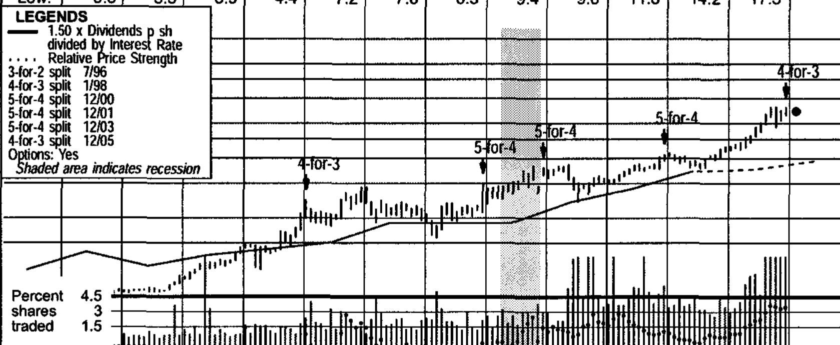
Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	6	0	0	1	2	3	2
to Sell	1	0	6	0	0	0	3	3	2

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	100	116	124
to Sell	57	64	73
Hld's(000)	34905	36632	37964

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:					3.8	4.1	5.7	8.5	11.5	11.5	12.0	14.8	15.0	16.8	18.5	29.2	
Low:					3.3	3.3	3.9	4.4	7.2	7.6	6.3	9.4	9.6	11.8	14.2	17.5	



Target Price Range 2008 | 2009 | 2010

64 48 40 32 24 20 16 12 8 6

% TOT. RETURN 12/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	50.4	6.8
3 yr.	135.5	85.4
5 yr.	158.5	70.4

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
3.40	2.02	2.14	1.82	1.70	1.82	1.84	1.86	2.02	2.09	2.41	2.46	2.70	2.85	2.97	3.48	*3.90*	*4.10*	Revenues per sh	*4.95*
.49	.43	.45	.39	.42	.42	.47	.50	.56	.61	.72	.76	.86	.94	.96	1.09	*1.25*	*1.35*	"Cash Flow" per sh	*1.80*
.20	.24	.25	.24	.24	.26	.29	.30	.34	.40	.42	.47	.51	.54	.57	.64	*.72*	*.81*	Earnings per sh A	*1.20*
.18	.19	.19	.20	.21	.21	.22	.23	.24	.26	.27	.28	.30	.32	.35	.37	.40	*.44*	Div'd Decl'd per sh B■	*.54*
.86	.76	.54	.60	.47	.46	.52	.48	.58	.82	.90	1.16	1.09	1.20	1.32	1.54	*1.70*	*1.90*	Cap'l Spending per sh	*2.45*
2.19	2.10	2.07	2.09	2.29	2.41	2.46	2.69	2.84	3.21	3.42	3.85	4.15	4.36	5.34	5.89	*6.30*		Book Value per sh	*9.20*
39.26	40.64	41.42	51.20	59.40	59.77	63.74	65.75	67.47	72.20	106.80	111.82	113.97	113.19	123.45	127.18	*128.00*	*130.00*	Common Shs Outst'g C	*136.00*
12.9	10.2	10.8	12.5	14.4	13.5	12.0	15.6	17.8	22.5	21.2	18.2	23.6	23.6	24.5	25.1	*31.5*		Avg Ann'l P/E Ratio	*23.0*
.98	.76	.69	.76	.85	.89	.80	.98	1.03	1.17	1.21	1.18	1.21	1.29	1.40	1.33	*1.65*		Relative P/E Ratio	*1.55*
6.9%	7.7%	7.2%	6.8%	5.9%	6.0%	6.2%	4.9%	3.9%	2.9%	3.0%	3.3%	2.5%	2.5%	2.5%	2.3%	1.8%		Avg Ann'l Div'd Yield	*2.4%*

CAPITAL STRUCTURE as of 9/30/05
Total Debt $995.9 mill. Due in 5 Yrs $220.0 mill.
LT Debt $854.5 mill. LT Interest $45.0 mill.
(Total interest coverage: 4.4x)

Pension Assets-12/04 $115.3 mill. Oblig. $171.1 mill.

Pfd Stock None

Common Stock 128,672,732 shares as of 10/25/05
(adj. for 4-for-3 stock split paid 12/1/05)
MARKET CAP: $3.6 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
117.0	122.5	136.2	151.0	257.3	275.5	307.3	322.0	367.2	442.0	*500*	*530*	Revenues ($mill)	*675*
19.0	19.8	23.2	28.8	45.0	50.7	58.5	62.7	67.3	80.0	*95.0*	*105*	Net Profit ($mill)	*160*
40.4%	41.4%	40.6%	40.5%	38.4%	38.9%	39.3%	38.5%	39.3%	39.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
1.6%	--	--	--	--	--	--	--	3.2%	2.9%	*1.5%*	*1.5%*	AFUDC % to Net Profit	*1.5%*
51.9%	54.1%	54.4%	52.7%	52.9%	52.0%	52.2%	54.2%	51.4%	50.0%	*51.5%*	*51.5%*	Long-Term Debt Ratio	*50.0%*
46.4%	44.0%	44.8%	46.6%	46.7%	47.8%	47.7%	45.8%	48.6%	50.0%	*48.5%*	*48.5%*	Common Equity Ratio	*50.0%*
338.0	401.7	427.2	496.6	782.7	901.1	990.4	1076.2	1355.7	1497.3	*1655*	*1840*	Total Capital ($mill)	*2500*
436.9	502.9	534.5	609.8	1135.4	1251.4	1368.1	1490.8	1824.3	2069.8	*2200*	*2340*	Net Plant ($mill)	*2820*
7.7%	6.8%	7.4%	7.6%	7.6%	7.4%	7.8%	7.6%	6.4%	6.7%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
11.7%	10.7%	11.9%	12.3%	12.2%	11.7%	12.3%	12.7%	10.2%	10.7%	*12.0%*	*12.0%*	Return on Shr. Equity	*13.0%*
11.7%	11.2%	12.0%	12.4%	12.3%	11.7%	12.4%	12.7%	10.2%	10.7%	*12.0%*	*12.0%*	Return on Com Equity	*13.0%*
3.5%	2.8%	3.6%	4.5%	4.3%	4.7%	5.1%	5.2%	4.2%	4.6%	*5.5%*	*5.5%*	Retained to Com Eq	*7.0%*
71%	75%	70%	64%	65%	60%	59%	59%	59%	57%	*54%*	*54%*	All Div'ds to Net Prof	*46%*

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	39.2	13.1	9.5
Receivables	62.3	64.5	69.6
Inventory (AvgCst)	5.8	6.9	8.4
Other	5.1	5.6	5.9
Current Assets	112.4	90.1	93.4
Accts Payable	32.3	23.5	18.5
Debt Due	135.8	135.3	141.4
Other	63.9	58.6	78.3
Current Liab.	232.0	217.4	238.2
Fix. Chg. Cov.	344%	364%	436%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.5%	7.5%	*8.0%*
"Cash Flow"	9.5%	9.5%	*10.0%*
Earnings	9.0%	8.5%	*13.0%*
Dividends	5.5%	6.5%	*8.0%*
Book Value	8.5%	10.5%	*10.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	71.7	76.6	91.9	81.8	322.0
2003	80.5	83.4	102.1	101.2	367.2
2004	99.8	106.5	120.3	115.4	442.0
2005	114.0	123.1	136.8	*126.1*	*500*
2006	*125*	*130*	*140*	*135*	*530*

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.10	.12	.19	.13	.54
2003	.11	.14	.18	.14	.57
2004	.13	.14	.20	.17	.64
2005	.15	.17	.22	*.18*	*.72*
2006	*.16*	*.19*	*.25*	*.21*	*.81*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.08	.08	.08	.084	.32
2003	.084	.084	.084	.09	.34
2004	.09	.09	.09	.098	.37
2005	.098	.098	.098	.108	.40
2006					

BUSINESS: Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately 2.5 million residents in Pennsylvania, Ohio, New Jersey, Illinois, Maine, North Carolina, Texas, Florida, Kentucky, and five other states. Divested three of four non-water businesses in '91; telemarketing group in '93; and others. Acquired AquaSource, 7/03; Consumers Water, 4/99; and others. Water supply revenues '04: residential, 60%; commercial, 15%; industrial & other, 25%. Officers and directors own 1.5% of the common stock (4/05 Proxy). Chairman & Chief Executive Officer: Nicholas DeBenedictis. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Telephone: 610-525-1400. Internet: www.aquaamerica.com.

Aqua America continues to meet expectations. There was little by way of surprises in the company's third-quarter report. Earnings of $0.22 per share matched our estimate, and revenues were just a notch higher than what we were expecting. It was a solid quarter that showcased Aqua's disciplined acquisition and cost-control strategies, as well as its proven record of rate recognition. The just-passed year likely ended with Aqua posting double-digit earnings growth. We expect this momentum to spill into 2006, which should help support another year of double-digit profit expansion. *(Note: All per-share data has been adjusted for a 4-for-3 stock split paid December 1, 2005.)*

Acquisitions play a central role in the company's growth strategy. Aqua successfully managed to integrate about 30 small businesses in 2005, and expects to make 25–30 more this year. The fragmented nature of the water utilities market makes Aqua's strategy even more effective. In fact, purchases will likely get easier for the water-utilities giant when later this year a stricter Environmental Protection Agency regulation takes effect, and smaller utilities find themselves hard pressed to meet the costly new requirements.

Rate case filings will likely reach record numbers in 2006, as the company tries to recoup costs associated with accelerating capital expenditures. The bulk of the roughly $60 million in expected rate filings this year will probably stem from Pennsylvania. Over the last two years, Aqua's capital spending in the state has topped $275 million. Given management's strong relationships with many of its state regulators, we feel the company will be able to pass a considerable amount of its rate requests through to the top line.

Shares of Aqua America are ranked 3 (average) for year-ahead relative performance. This stock rose 50% in 2005, making its current valuation quite high. Our projections, however, show earnings growth will likely not be able to keep pace with share-price movement, making the likelihood of this valuation being sustainable low. As a result, Aqua's total-return potential for the years out to 2008–2010 seems limited.

Praneeth Satish *January 27, 2006*

(A) Primary shares outstanding through '96; diluted thereafter. Excl. nonrec. gains (losses): '90, (38¢); '91, (34¢); '92, (38¢); '99, (11¢); '00, 2¢; '01, 2¢; '02, 5¢; '03, 4¢; '05, 17¢. Excl. gain from disc. operations: '96, 2¢. Next earnings report due early February. (B) Dividends historically paid in early March, June, Sept. & Dec. ■ Div'd. reinvestment plan available (5% discount). (C) In millions, adjusted for stock splits. (D) May not sum due to rounding.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	95
Earnings Predictability	100

ATTACHMENT C

The Natural Gas Distribution Industry is ranked near the bottom of the *Value Line* universe for Timeliness: 95 of (98). The key features of gas utility stocks are their safety and better-than-average dividend yields, rather than price performance or appreciation potential. It should be noted that the distribution industry is in the middle of its most profitable quarters, thanks to the winter heating season.

Regulated Utilities

Local distribution companies (LDCs) are natural gas utilities that are regulated by both individual state and/or federal regulatory agencies. They are considered natural monopolies since it is more cost-effective to build one pipeline system to serve a region, versus multiple distributors competing over the same location. Since these companies are essentially able to operate as monopolies, the government sets allowable rates of return each company can earn, typically between 10% and 12%. This is one of the contributing factors to the limited volatility in share prices for these distributors. However, should earnings be less than the permitted rate, the company is able to petition regulators for higher rates. Likewise, if it is determined that a distributor is earning in excess of its allowable rates, it may be subject to a rate review. In addition, some companies now have weather plans in place to protect against abnormal temperatures. Two such companies are *WGL Holdings* in its Maryland service territory, and *Southwest Gas.* The Maryland weather-normalization program protects the company against revenue variations due to changes in usage, caused by weather deviations from the norm, along with conservation among customers. *Southwest* is awaiting a rate case decision in Arizona, which would mitigate the impact of weather on earnings and allow the company to recover higher costs. Programs such as these create a more consistent year-over-year earnings stream.

Nonregulated Activities

Industry deregulation has allowed gas utilities to expand their businesses beyond their normal distribution operations. The companies that expand into those arenas enjoy the opportunity to enter businesses with no restrictions on return on equity. Some activities include retail energy marketing, energy trading, and oil and gas exploration and production. In fact, nearly all of the companies in this industry have at least some exposure to the nonregulated segment, with many looking to further expand operations here. One such company is *South Jersey* at its Marina Energy unit. The division will be expanding its Atlantic City thermal electric plant to support the scheduled 500,000-square-foot expansion at the Borgata Hotel casino & Spa.

INDUSTRY TIMELINESS: 95 (of 98)

Natural Gas Prices

Natural gas prices reached lofty levels following the hurricanes that hit the Gulf Coast. Although they came down somewhat, they were still high compared to prior years. Prices have recently returned to these high levels, most likely because of cold weather in the Northeast. Typically, those companies that are involved in nonregulated activities stand to benefit the most from higher prices. The regulated utilities continue to earn their allowable rate of return, but the added expenses are eventually passed on to customers in the form of higher utility bills. These added charges then result in a higher level of bad debt expense, since some low-income customers are unable to afford these bills. Sharply rising bills can also result in the loss of customers to other fuels. If the winter turns out to be colder than normal, gas volume use will likely increase. However, due to high gas prices, customers may well begin to conserve to cut down on their utility bills, thereby lowering profits.

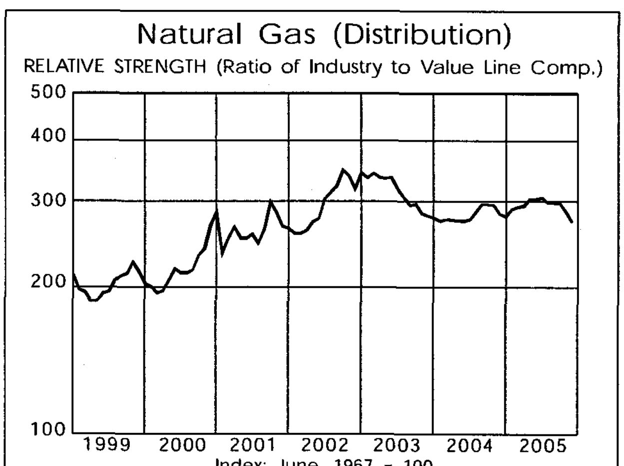
Investment Advice

The stocks in this industry are generally suitable for income-oriented investors, and offer good stock price stability. Risk-adverse investors still may want to primarily focus on those companies that derive most of their earnings from regulated activities. As companies have begun to shift their operations toward nonregulated businesses, the potential for capital appreciation is increased, but so is the risk for capital losses. Note that especially high dividend yields for stocks in this sector can mean growth opportunities are constrained. Also, as companies expand into nonregulated activities they may be less willing to raise the dividend payout, instead using these funds to finance capital expenditures.

Evan I. Blatter

Composite Statistics: Natural Gas (Distribution)

2001	2002	2003	2004	2005	2006		08-10
27611	22947	29981	33220	***35000***	***37950***	Revenues ($mill)	***42000***
1070.4	1231.5	1395.3	1735.9	***1750***	***1850***	Net Profit ($mill)	***2100***
39.7%	35.3%	37.4%	35.6%	***36.0%***	***36.0%***	Income Tax Rate	***36.0%***
3.9%	5.4%	4.7%	5.2%	***5.0%***	***4.9%***	Net Profit Margin	***5.0%***
57.4%	57.8%	55.9%	53.2%	***53.0%***	***53.0%***	Long-Term Debt Ratio	***52.5%***
41.5%	41.4%	43.7%	45.7%	***45.0%***	***45.0%***	Common Equity Ratio	***45.5%***
24342	24907	28436	31268	***33500***	***35400***	Total Capital ($mill)	***39450***
24444	25590	31732	32053	***33500***	***35000***	Net Plant ($mill)	***40000***
6.1%	6.6%	6.4%	7.1%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.0%***
10.3%	11.7%	11.1%	11.9%	***12.0%***	***12.0%***	Return on Shr. Equity	***12.5%***
10.5%	11.8%	11.2%	12.0%	***12.0%***	***12.0%***	Return on Com Equity	***12.5%***
2.5%	3.9%	4.1%	5.5%	***5.5%***	***5.5%***	Retained to Com Eq	***5.5%***
76%	68%	64%	55%	***60%***	***60%***	All Div'ds to Net Prof	***60%***
16.8	14.8	14.1	13.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***13.0***
.86	.81	.80	.72			Relative P/E Ratio	***.87***
4.5%	4.5%	4.5%	4.0%			Avg Ann'l Div'd Yield	***4.6%***
244%	280%	314%	308%	***315%***	***330%***	Fixed Charge Coverage	***375%***



CASCADE NAT'L GAS NYSE-CGC

RECENT PRICE	20.20	P/E RATIO	22.7 (Trailing: 24.6 Median: 18.0)	RELATIVE P/E RATIO	1.23	DIV'D YLD	4.8%	VALUE LINE

TIMELINESS 4 Raised 9/23/05
SAFETY 3 New 7/27/90
TECHNICAL 3 Raised 5/13/05
BETA .80 (1.00 = Market)

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+50%)	14%
Low	20	(Nil)	5%

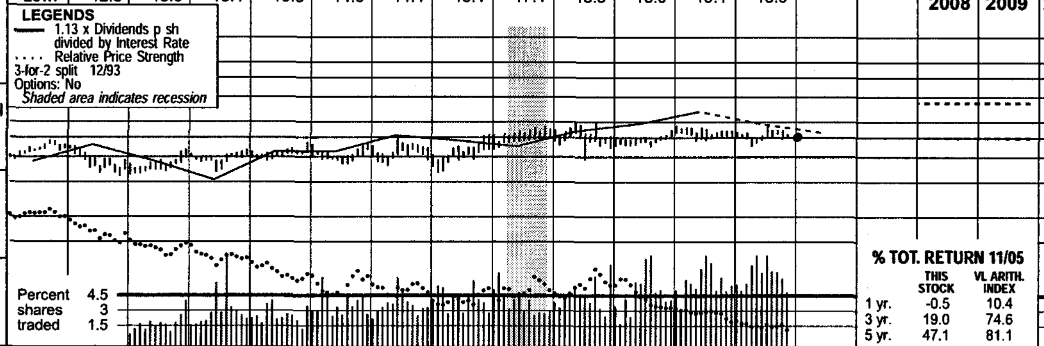
Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	1	0	1	0	2	1	0	0	0
Options	0	2	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	37	35	44
to Sell	40	37	28
Hld's(000)	4743	4474	4775

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	18.1	17.5	17.5	19.0	18.7	19.8	20.9	22.8	24.2	22.0	23.0	22.8
Low:	12.8	13.0	13.4	15.3	14.6	14.4	13.4	17.4	15.5	18.0	19.1	18.0



Target Price Range
2008 | 2009 | 2010

% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	-0.5	10.4
3 yr.	19.0	74.6
5 yr.	47.1	81.1

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
26.87	24.45	23.27	20.03	21.88	21.59	19.98	11.84	17.85	17.17	18.89	21.90	30.40	29.06	27.20	28.23	28.60	29.80	Revenues per sh A	40.00
2.47	2.36	2.29	1.66	2.04	1.71	2.07	1.22	1.92	2.06	2.40	2.60	2.72	2.48	2.25	2.63	2.30	2.65	"Cash Flow" per sh	3.60
1.29	1.26	1.14	.63	1.05	.60	.80	.39	.93	.84	1.24	1.39	1.47	1.13	.87	1.19	.82	.95	Earnings per sh AB	1.25
.85	.87	.90	.93	.94	.96	.96	.72	.96	.96	.96	.96	.96	.96	.96	.96	.96	.96	Div'ds Decl'd per sh C■	.98
1.99	2.50	2.97	4.64	3.85	3.06	4.12	2.42	2.66	2.32	1.81	1.65	2.16	1.91	2.56	3.50	2.50	3.05	Cap'l Spending per sh	4.40
7.96	8.33	8.63	9.09	9.96	9.81	9.76	10.09	10.16	10.07	10.36	10.79	11.01	10.34	10.11	10.52	10.45	10.95	Book Value per sh D	15.30
6.49	6.56	6.63	7.61	8.57	8.91	9.14	10.79	10.97	11.05	11.05	11.05	11.05	11.05	11.13	11.27	11.41	11.40	Common Shs Outst'g E	12.00
8.6	8.9	12.2	23.7	16.6	25.7	18.2	40.0	17.6	19.4	13.7	11.7	13.4	18.2	22.0	17.5	25.1		Avg Ann'l P/E Ratio	20.0
.65	.66	.78	1.44	.98	1.69	1.22	2.51	1.01	1.01	.78	.76	.69	.99	1.25	.92	1.32		Relative P/E Ratio	1.35
7.7%	7.8%	6.4%	6.2%	5.4%	6.2%	6.6%	4.6%	5.9%	5.9%	5.7%	5.9%	4.9%	4.7%	5.0%	4.6%	4.7%		Avg Ann'l Div'd Yield	3.9%

CAPITAL STRUCTURE as of 6/30/05

Total Debt $180.9 mill. **Due in 5 Yrs** $55.0 mill.
LT Debt $158.9 mill. **LT Interest** $10.0 mill.
(LT interest earned: 2.8x; total interest coverage: 2.7x)

Pension Assets-9/04 $51.3 mill. **Oblig.** $65.5 mill.

Pfd Stock None

Common Stock 11,413,000 shs. as of 9/30/05

MARKET CAP: $225 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
182.7	127.7	195.8	189.7	208.6	241.9	335.8	321.0	302.8	318.1	326.5	340	Revenues ($mill) A	480
7.7	4.2	10.6	9.8	14.2	15.4	16.2	12.5	9.7	13.3	9.2	11.0	Net Profit ($mill)	15.0
36.8%	34.8%	37.1%	37.4%	36.5%	37.1%	35.0%	34.9%	34.2%	36.2%	37.9%	37.5%	Income Tax Rate	38.5%
4.2%	3.3%	5.4%	5.2%	6.8%	6.4%	4.8%	3.9%	3.2%	4.2%	2.8%	3.2%	Net Profit Margin	3.1%
51.4%	46.8%	50.6%	48.4%	50.9%	51.2%	50.7%	59.1%	55.9%	52.1%	56.0%	55.0%	Long-Term Debt Ratio	51.0%
45.0%	50.0%	46.5%	48.7%	46.6%	48.8%	49.3%	40.9%	44.1%	47.9%	44.0%	45.0%	Common Equity Ratio	49.0%
198.5	217.8	239.4	228.5	245.6	244.2	246.6	279.1	255.5	247.4	300	320	Total Capital ($mill)	375
239.1	255.7	265.2	276.6	282.3	284.8	294.2	299.6	312.3	334.6	350	375	Net Plant ($mill)	475
5.9%	3.4%	6.2%	6.1%	7.5%	8.1%	8.5%	6.4%	6.0%	7.7%	5.0%	5.5%	Return on Total Cap'l	5.5%
8.0%	3.6%	9.0%	8.3%	11.7%	12.9%	13.3%	10.9%	8.6%	11.2%	7.5%	9.0%	Return on Shr. Equity	8.5%
8.1%	3.5%	9.1%	8.3%	12.0%	12.9%	13.3%	10.9%	8.6%	11.2%	7.5%	9.0%	Return on Com Equity	8.5%
NMF	NMF	.7%	NMF	2.7%	4.0%	4.6%	1.7%	NMF	2.1%	NMF	Nil	Retained to Com Eq	2.0%
106%	NMF	93%	108%	78%	69%	65%	85%	110%	81%	119%	99%	All Div'ds to Net Prof	78%

CURRENT POSITION A ($MILL.)	2003	2004	6/30/05
Cash Assets	7.5	.5	.7
Other	33.1	65.9	64.8
Current Assets	40.6	66.4	65.5
Accts Payable	10.5	12.9	11.0
Debt Due	25.8	47.5	22.0
Other	19.7	38.6	38.8
Current Liab.	56.0	99.0	71.8
Fix. Chg. Cov.	213%	269%	260%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	3.0%	9.5%	6.0%
"Cash Flow"	3.0%	3.0%	6.5%
Earnings	3.5%	1.0%	3.0%
Dividends	--	--	.5%
Book Value	.5%	--	7.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	102.8	122.3	56.8	39.1	321.0
2003	100.5	109.3	53.8	39.2	302.8
2004	104.9	119.4	52.1	41.7	318.1
2005	104.6	117.7	56.3	47.9	326.5
2006	107	125	60.0	48.0	340

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.56	.86	d.06	d.23	1.13
2003	.60	.67	d.18	d.22	.87
2004	.72	.79	d.05	d.26	1.19
2005	.59	.65	d.10	d.32	.82
2006	.62	.68	d.09	d.26	.95

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.24	.24	.24	.24	.96
2002	.24	.24	.24	.24	.96
2003	.24	.24	.24	.24	.96
2004	.24	.24	.24	.24	.96
2005	.24	.24	.24	.24	

BUSINESS: Cascade Natural Gas Corporation distributes natural gas to around 227,000 customers in Washington and Oregon. In 2004, total throughput was 113.4 billion cu. ft. Core customers: *residential, commercial, firm industrial, interruptible (69% of oper. margin, 23% of gas deliveries)*; non-core: industrial, transportation service (31%, 77%). Serves pulp & paper, plywood, chem. fertilizers, oil refining, & food process. inds. Main connecting pipeline: Northwest Pipeline Corp. '04 deprec. rate: 6.5%. Est'd plant age: 12 yrs. Has around 430 employees. Officers and directors own 1.7% of *com. (12/04 proxy)*. President and Chief Executive Officer: David W. Stevens. Inc.: WA. Address: 222 Fairview Ave. North, Seattle, WA 98109. Tel.: 206-624-3900. Internet: www.cngc.com.

We believe that Cascade Natural Gas' bottom line will recover some in fiscal 2006, which began October 1st. This should come about partly by further expansion of the customer base, an adjustment in the employee benefits plan, and savings from a consolidated call center for customers. The company should also be helped by the absence of costs stemming from the transition to a new executive team, and staff reductions (which, combined, amounted to $0.13 a share last year). But demand from residential and commercial customers may be held back, to a certain extent, by conservation efforts caused by persistently high natural gas prices and improved energy efficiency in buildings and appliances. Too, it seems that margins from the gas management services business will continue to suffer from competition from energy marketers, a segment that has made a comeback since the demise of Enron. All things considered, Cascade's earnings per share may well advance to $0.95 in fiscal 2006.

We remain positive about the company's 2008-2010 prospects. Generally favorable economic conditions in Washington and Oregon helped annual account hookups to rise at a steady rate in the past, and it appears that this trend will continue. Also, given the environmental advantages of natural gas and assuming that prices for this fuel source don't get out of reach for the mainstream, a significant portion of new customers may still come from conversions. These factors ought to enable annual bottom-line gains to be in the upper-single-digit range over the coming 3- to 5-year period.

Cascade shares, ranked 4 (Below Average) for Timeliness, offer a decent dividend yield. But additional increases in the payout will likely be slow in coming, as cash flows are used to meet the requirements of a growing customer base. Another factor to consider is the sensitivity of earnings to changes in service-area temperatures, given the absence of weather-normalization adjustment mechanisms. (Management is seeking a rate design that would diminish the temperature impact, but it's unclear, at this juncture, when regulators would approve such a measure.)

Frederick L. Harris, III December 16, 2005

(A) Cal. yr. thru. 12/95. Changed to 9/30 fiscal yr. in '96. (B) Primary egs. thru. '97, then diluted. Excl. nonrec. gains (losses): '91, 19¢; '93, 3¢; '96, (11¢); '98, (2¢); '99, (1¢); '01, 9¢; '02, (16¢); '03, (5¢). '04 egs. don't add to total due to rounding. Next egs. rpt. due late Jan. (C) Dividends historically paid in the middle of Feb., May, Aug., Nov. ■Div'd reinvest. plan avail. (D) Incl. deferred charges. In '04: $21.4 mill., $1.90/sh. (E) In mill., adj. for stk. split.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	55
Earnings Predictability	70

KEYSPAN CORP. NYSE-KSE

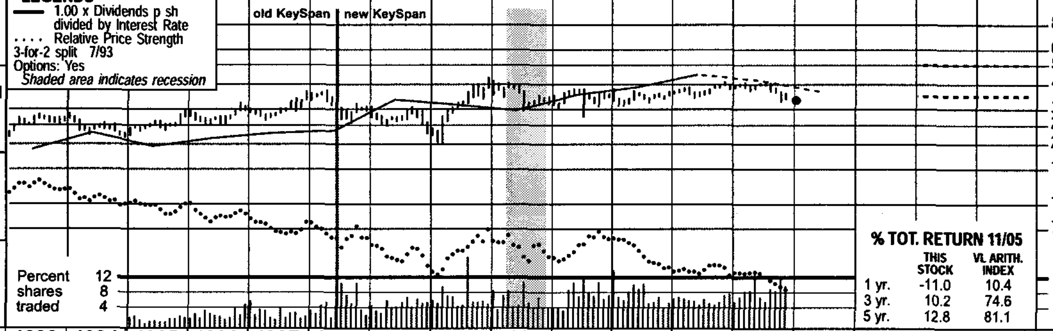
RECENT PRICE	33.37	P/E RATIO	13.5 (Trailing: 13.0 / Median: 14.0)	RELATIVE P/E RATIO	0.73	DIV'D YLD	5.5%	VALUE LINE

TIMELINESS **4** Lowered 12/10/04
SAFETY **2** Lowered 3/26/99
TECHNICAL **4** Lowered 12/2/05
BETA .85 (1.00 = Market)

High:	28.6	29.6	32.6	37.1	37.6	31.3	43.6	41.9	38.2	38.1	41.5	41.0	
Low:	21.5	22.0	24.9	26.1	25.4	22.5	20.2	29.1	27.4	31.0	33.9	32.7	

Target Price Range 2008 | 2009 | 2010

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 7/93
Options: Yes
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+50%)	15%
Low	35	(+5%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	4	0	5	1	2	0	0
to Sell	0	0	4	0	6	1	2	0	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	138	196	170
to Sell	135	85	118
Hld's(000)	81446	90574	90849

Percent shares traded 12 8 4

% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	-11.0	10.4
3 yr.	10.2	74.6
5 yr.	12.8	81.1

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
26.71	26.64	23.43	24.74	25.99	28.13	24.93	28.72	29.12	13.20	22.07	37.56	47.57	41.92	43.31	41.35	*40.10*	*41.45*	Revenues per sh A	*48.00*
2.64	2.62	2.38	3.03	3.04	3.29	3.35	3.54	4.27	.45	3.57	4.51	5.72	6.36	6.22	5.88	*4.65*	*4.80*	"Cash Flow" per sh	*5.60*
1.68	1.62	1.45	1.35	1.73	1.85	1.90	1.96	2.12	d1.34	1.62	2.10	1.72	2.75	2.62	2.44	*2.45*	*2.50*	Earnings per sh B	*3.10*
1.19	1.23	1.27	1.29	1.32	1.35	1.39	1.42	1.46	1.50	1.78	1.78	1.78	1.78	1.78	1.79	*1.82*	*1.82*	Div'ds Decl'd per sh C ■	*2.10*
4.30	3.51	3.44	3.95	4.37	4.15	4.36	6.04	5.60	5.19	5.42	4.64	7.60	7.96	6.34	4.89	*3.60*	*3.60*	Cap'l Spending per sh	*3.80*
13.36	13.68	14.37	14.55	15.54	16.27	16.94	18.17	19.09	23.18	20.28	20.65	20.73	20.67	22.94	24.22	*25.40*	*25.45*	Book Value per sh D	*29.50*
36.29	37.30	42.28	43.45	46.38	47.59	48.79	49.86	50.77	130.42	133.87	136.36	139.43	142.42	159.66	160.82	*174.50*	*175.00*	Common Shs Outst'g E	*177.00*
10.1	11.9	13.1	15.1	14.3	13.7	12.7	13.7	13.8	--	16.8	14.8	20.8	12.7	13.1	15.3	Bold figures are		Avg Ann'l P/E Ratio	*13.5*
.76	.88	.84	.92	.84	.90	.85	.86	.80	--	.96	.96	1.07	.69	.75	.82	Value Line		Relative P/E Ratio	*.90*
7.0%	6.4%	6.7%	6.4%	5.3%	5.3%	5.8%	5.3%	5.0%	4.8%	6.5%	5.7%	5.0%	5.1%	5.2%	4.8%	estimates		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 9/30/05
Total Debt $4.236 bill. **Due in 5 Yrs** $2.5 bill.
LT Debt $3.915 bill. **LT Interest** $280 mill.
(total interest coverage: 3.8x)

Pension Assets-12/04 $1.9 bill. **Oblig.** $2.3 bill.

Pfd Stock None **Pfd Div'd** Nil

Common Stock 174,361,293 shs.
as of 10/12/05
MARKET CAP: $5.8 billion (Large Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1216.3	1432.0	1478.2	1721.9	2954.6	5121.5	6633.1	5970.7	6915.2	6650.5	*7000*	*7250*	Revenues ($mill) A	*8500*
91.8	97.2	106.1	d166.9	258.6	300.8	243.7	397.4	424.2	398.7	*410*	*440*	Net Profit ($mill)	*550*
32.0%	28.9%	35.0%	--	34.5%	41.8%	46.4%	36.2%	39.5%	34.6%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
7.6%	6.8%	7.2%	NMF	8.8%	5.9%	3.7%	6.7%	6.1%	6.0%	*5.9%*	*6.1%*	Net Profit Margin	*6.5%*
46.4%	43.8%	43.5%	31.8%	37.5%	59.6%	61.2%	63.3%	60.0%	53.0%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*49.0%*
53.2%	55.8%	56.5%	59.4%	60.6%	39.2%	37.7%	35.7%	39.1%	46.7%	*53.0%*	*53.0%*	Common Equity Ratio	*51.0%*
1553.8	1624.4	1714.1	5089.9	4482.1	7175.0	7672.3	8252.5	9356.9	8333.1	*8400*	*8700*	Total Capital ($mill)	*10000*
1512.6	1698.1	1810.6	3778.3	4240.0	6358.3	6605.9	7217.6	8894.3	7067.9	*7300*	*7500*	Net Plant ($mill)	*8500*
7.5%	7.4%	7.3%	NMF	7.1%	5.3%	4.5%	6.2%	5.8%	8.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
11.0%	10.7%	10.9%	NMF	9.2%	10.4%	8.2%	13.1%	11.3%	10.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
11.1%	10.7%	10.9%	NMF	8.2%	10.0%	8.2%	13.3%	11.4%	10.2%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
2.9%	2.9%	3.3%	NMF	NMF	1.4%	NMF	4.8%	3.9%	2.3%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
74%	73%	70%	NMF	110%	86%	103%	65%	66%	73%	*74%*	*73%*	All Div'ds to Net Prof	*68%*

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	205.8	922.0	84.0
Other	2181.1	2156.6	2869.4
Current Assets	2386.9	3078.6	2200.4
Accts Payable	1141.6	906.7	756.3
Debt Due	483.4	928.3	321.5
Other	223.8	447.3	631.1
Current Liab.	1848.8	2282.3	1708.9
Fix. Chg. Cov.	315%	257%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.0%	13.5%	*3.0%*
"Cash Flow"	8.0%	17.0%	*-.5%*
Earnings	4.5%	21.0%	*1.0%*
Dividends	3.0%	4.0%	*2.0%*
Book Value	4.0%	1.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1871	1215	1076	1807	5970.7
2003	2512	1408	1131	1862	6915.2
2004	2595	1365	1050	1638	6650.5
2005	2480	1342	1303	*1875*	*7000*
2006	*2700*	*1425*	*1200*	*1925*	*7250*

Cal-endar	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.51	.20	.02	1.02	2.75
2003	1.53	d.05	.07	1.07	2.62
2004	1.39	.13	.03	.88	2.43
2005	1.43	.11	.13	*.78*	*2.45*
2006	*1.47*	*.10*	*.05*	*.88*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID A C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.445	.445	.445	.445	1.78
2002	.445	.445	.445	.445	1.78
2003	.445	.445	.445	.445	1.78
2004	.445	.445	.445	.445	1.78
2005	.455	.455	.455	.455	

BUSINESS: KeySpan Corp. is a holding company created 5/98, via *the merger of KeySpan Energy (formerly Brooklyn Union) and Long* Island Lighting. Acq. Eastern Enterprises 11/00, making KeySpan the largest gas distributor in the Northeast, serving most of New York City and nearby Long Island, and parts of New England. Has 2.5 mill. gas meters in one-family homes and apartments. Also generates electricity and operates transmission/distr. sys. by contract with L.I. Power Author. Sold its stake in Houston Exploration, 2004. Owns 20% of Iroquois Pipeline. Non-regulated subs. market gas supplies, sell ind'l energy mgmt. svcs. Has 9,950 empls. Chrmn.: R.B. Catell. Inc.: NY. Address: 1 MetroTech Center, Brooklyn, NY 11201. Tel.: 718-403-1000. Web:www.keyspanenergy.com.

KeySpan's third-quarter earnings came in better than expected. (Our estimate was a loss of a penny a share.) Electric services profits jumped 34% as a result of weather that was 50% warmer than normal, fuel price spreads, and good online performance by the generating plants. That more than offset increased losses in the gas distribution business (which usually loses money in the summer), due in part to higher uncollectible debts. Finally, interest costs declined 24% from the prior-year period, thanks to an 11% reduction in outstanding debt since the end of 2004 and debt refinancing. We think that uncollectible debts will remain above recent levels through next winter.

The earnings outlook for 2006 is mixed. On the plus side, the company will probably hook up enough new gas customers in 2005 to raise gross profits by around $40 million in 2006. And Massachusetts has approved a regulatory change that *should permit KeySpan to recover more* uncollectible debts. But gas customers will probably pay 30% to 40% more for heat this winter, an unprecedented jump that could result in very high bad debts and noticeable conservation. Electric service earnings could suffer in 2006 if a planned 10% generating capacity increase in New York City actually comes on line. New York regulators, however, will probably raise the amount of power that must be generated in the City, mitigating the effects of new capacity. Finally, the sideline energy services business should lose a bit less or even make a little money.

Longer term, share net should rise at a modest pace. KeySpan has over 500,000 prospective gas customers near its mains that could be hooked up relatively easily. New York City's power demands should grow steadily and yield more profits, despite some possible excess capacity in 2006. And, having reduced its debt-to-capital ratio to around 47%, the company could invest several hundred million dollars in acquisitions without endangering its credit ratings.

These untimely shares offer decent risk-adjusted total return potential. KSE's dividend yield is above the industry average, and the company has some growth prospects.

Sigourney B. Romaine December 16, 2005

(A) Data for former KeySpan Energy through '97 (years ended 9/30); new KeySpan Corp. from '98 on a calendar fiscal year. (B) Diluted shs. Excl. nonrecur. gains (charges): '90, ($0.19); '96, $0.52; '97, $0.16; '03, ($0.23); '04, ($0.40). Excl. gain (loss) discont. ops.: '00, ($0.02); '01, ($0.14); '02, ($0.14); '03, $0.01; '04, $0.81. Next egs. report due late Jan. (C) Divs historically paid early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. (D) Includes def. charges. At 12/31/04: $18.31 /sh. (E) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	20

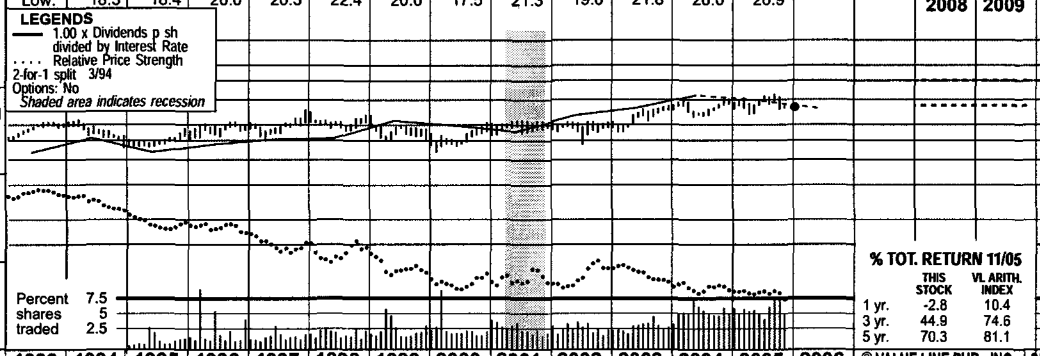
LACLEDE GROUP NYSE-LG

RECENT PRICE	29.32	P/E RATIO	14.7 (Trailing: 15.4, Median: 15.0)	RELATIVE P/E RATIO	0.80	DIV'D YLD	4.7%	VALUE LINE

TIMELINESS 4 Raised 8/5/05
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Lowered 11/18/05
BETA .80 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	25.6	23.1	24.9	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3
Low:	18.3	18.4	20.0	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/94
Options: No
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+35%)	*12%*
Low	30	(Nil)	*6%*

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	1	0	0	0	0	0	3
to Sell	0	3	1	0	0	0	0	0	3

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	54	48	51
to Sell	38	45	35
Hld's(000)	6440	6362	6774

% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	-2.8	10.4
3 yr.	44.9	74.6
5 yr.	70.3	81.1

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
31.57	30.21	28.10	26.83	32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	*76.05*	*85.10*	Revenues per sh	*116.30*
2.47	2.13	2.37	2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	*3.15*	*3.35*	"Cash Flow" per sh	*4.15*
1.45	1.08	1.28	1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	*2.00*	Earnings per sh A B	*2.30*
1.15	1.18	1.20	1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	*1.39*	Div'ds Decl'd per sh C■	*1.45*
1.82	1.87	2.46	2.87	2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	*2.85*	*3.00*	Cap'l Spending per sh	*3.75*
11.74	11.75	11.83	11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	*17.45*	*19.00*	Book Value per sh D	*27.35*
15.59	15.59	15.59	15.59	15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	*21.00*	*21.50*	Common Shs Outst'g E	*21.50*
10.3	14.6	12.5	15.8	13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2		Avg Ann'l P/E Ratio	*15.5*
.78	1.08	.80	.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.82	.85		Relative P/E Ratio	*1.05*
7.7%	7.5%	7.5%	6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%		Avg Ann'l Div'd Yield	*4.1%*

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
431.9	544.8	602.8	547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	*1830*	Revenues ($mill) A	*2500*
20.9	32.8	32.5	27.9	26.9	26.0	30.5	22.4	34.6	36.1	40.1	*45.0*	Net Profit ($mill)	*50.0*
32.1%	35.9%	36.1%	35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	*35.0%*	Income Tax Rate	*35.0%*
4.8%	6.0%	5.4%	5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	*2.5%*	Net Profit Margin	*2.0%*
40.2%	42.5%	38.0%	40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	*48.0%*	*49.0%*	Long-Term Debt Ratio	*51.0%*
59.3%	57.1%	61.6%	58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	*52.0%*	*51.0%*	Common Equity Ratio	*49.0%*
383.5	422.2	406.8	438.0	488.6	519.2	574.1	546.6	605.0	737.4	*710*	*800*	Total Capital ($mill)	*1200*
434.3	452.2	467.6	490.6	519.4	575.4	602.5	594.4	621.2	646.9	*680*	*705*	Net Plant ($mill)	*950*
7.1%	9.4%	9.7%	8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	*7.0%*	*7.0%*	Return on Total Cap'l	*5.5%*
9.1%	13.5%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	*11.0%*	*11.0%*	Return on Shr. Equity	*8.5%*
9.2%	13.6%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	*11.0%*	*11.0%*	Return on Com Equity	*8.5%*
.4%	4.5%	3.9%	1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	*3.0%*	*3.5%*	Retained to Com Eq	*3.0%*
96%	67%	70%	83%	89%	98%	83%	113%	74%	73%	*72%*	*66%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 6/30/05
Total Debt $427.9 mill. Due in 5 Yrs $175.0 mill.
LT Debt $340.4 mill. LT Interest $25.0 mill.
(Total interest coverage: 2.9x)

Leases, Uncapitalized Annual rentals $1.6 mill.
Pension Assets-9/04 $259.5 mill. Oblig. $252.6 mill.
Pfd Stock $1.1 mill. Pfd Div'd $.06 mill.
Common Stock 21,143,581 shs. as of 7/29/05

MARKET CAP: $625 million (Small Cap)

CURRENT POSITION ($MILL.)	2003	2004	6/30/05
Cash Assets	7.3	13.9	4.8
Other	280.6	323.7	275.8
Current Assets	287.9	337.6	280.6
Accts Payable	66.0	68.4	89.4
Debt Due	218.2	96.5	87.5
Other	82.1	97.7	82.3
Current Liab.	366.3	262.6	259.2
Fix. Chg. Cov.	295%	279%	280%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.0%	11.0%	*14.5%*
"Cash Flow"	1.0%	-1.0%	*6.5%*
Earnings	1.5%	-.5%	*6.0%*
Dividends	1.0%	.5%	*1.5%*
Book Value	2.5%	1.5%	*9.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	194.6	287.5	147.3	125.8	755.2
2003	280.1	422.2	186.6	161.4	1050.3
2004	332.6	475.0	245.1	197.6	1250.3
2005	442.5	576.5	311.3	266.7	1597.0
2006	*515*	*635*	*365*	*315*	*1830*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.41	1.10	d.05	d.28	1.18
2003	.80	1.14	.11	d.21	1.82
2004	.87	1.12	.19	d.28	1.82
2005	.79	1.06	.29	d.24	1.90
2006	*.83*	*1.13*	*.28*	*d.24*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.335	.335	.335	.335	1.34
2002	.335	.335	.335	.335	1.34
2003	.335	.335	.335	.335	1.34
2004	.335	.34	.34	.34	1.36
2005	.34	.345	.345	.345	

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri (population, 2 million), including the city of St. Louis, St. Louis County, and parts of 8 other counties. Has more than 630,000 customers. Purchased SM&P for $43 million (1/02). Therms sold and transported in fiscal '04: 1.12 mill. Revenue mix for regulated operations: residential, 63%; commercial and industrial, 23%; transportation, 2%; other, 12%. Has around 3,440 employees. Officers and directors own approximately 6.0% of common shares (1/05 Proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.lacledegas.com.

Laclede Group's core natural gas distribution unit, Laclede Gas, could have a rough time in fiscal 2006 (which ends September 30th). Volumes may be held in check by conservation efforts spurred by persistently high natural gas prices. Furthermore, operating expenses should continue to rise, reflecting increased rates charged by suppliers and higher off-system gas costs. But performance ought to be aided partly by a hedging program intended to limit gas-price volatility, and a weather-mitigation mechanism that has been in effect since 2002. Too, a rate hike was recently approved by the Missouri Public Service Commission, although less than what management requested.

The other segments stand to deliver decent results this year, though. SM&P Utility Resources, the unregulated unit specializing in locating and marking services for underground facilities, should benefit from additional business in both new and existing markets, plus improvements in operational efficiency. Meanwhile, we expect earnings for Laclede Energy Resources, the non-utility gas marketing segment, to be boosted by a steady rise in interstate pipeline wholesale transactions. Nevertheless, consolidated share net may advance only 5%, to $2.00, in fiscal 2006.

The company's prospects out to the end of this decade are unspectacular, too, given that Laclede Gas is operating in a mature market. Indeed, the customer base has been expanding roughly 1% annually, which means that internal growth for this business will remain moderate, at best. As such, any substantial gains will have to come from the unregulated units or from acquisitions, scenarios we don't see happening anytime soon. That said, annual bottom-line increases ought to be in the mid-single-digit range over the 2008-2010 period.

Long-term total-return potential for the equity is limited, given that it is already trading near our 3- to 5-year Target Price Range, and assuming moderate increases in the dividend. Meanwhile, these good-yielding shares are ranked to underperform the broader market averages for the next six to 12 months.

Frederick L. Harris, III December 16, 2005

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Next earnings report due late Jan.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '04: $206.6 mill., $9.85/sh.
(E) In millions. Adjusted for stock split.
(F) Qtly. egs. may not sum due to change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	65

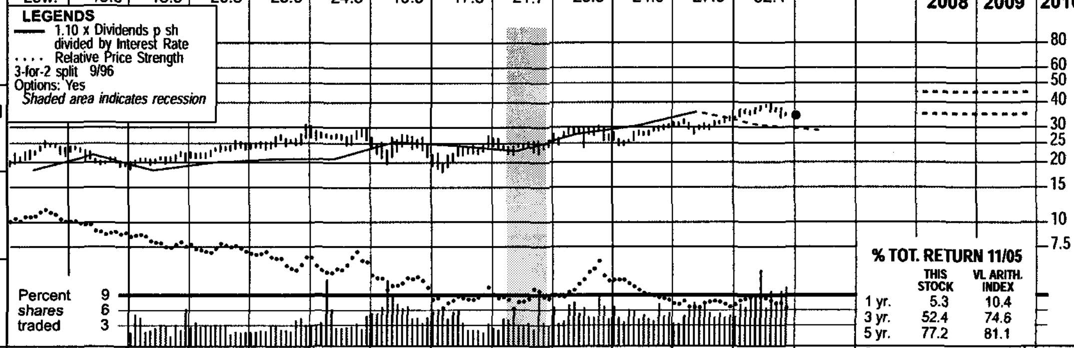
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **34.40** | P/E RATIO **15.6** (Trailing: 16.3 / Median: 14.0) | RELATIVE P/E RATIO **0.85** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS 4 Lowered 9/16/05
SAFETY 1 Raised 3/18/05
TECHNICAL 4 Lowered 12/2/05
BETA .70 (1.00 = Market)

High:	24.3	22.8	25.9	31.4	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6
Low:	18.8	18.3	20.8	23.0	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4

Target Price Range 2008 | 2009 | 2010



% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	5.3	10.4
3 yr.	52.4	74.6
5 yr.	77.2	81.1

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	11%
Low	35	(Nil)	5%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	4	2	0	0	4	0	0	1
to Sell	0	4	2	0	0	3	0	0	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	58	77	65
to Sell	51	38	49
Hld's(000)	12963	13459	13457

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
15.22	17.02	16.74	14.10	18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	32.45	33.90	Revenues per sh	37.95
2.85	3.22	2.57	3.25	3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.35	4.50	"Cash Flow" per sh	5.15
1.58	1.62	.67	.74	1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.15	2.25	Earnings per sh A	2.75
1.07	1.10	1.13	1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.34	1.39	Div'ds Decl'd per sh B ■	1.64
3.36	3.85	3.58	3.73	3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.60	3.35	Cap'l Spending per sh	4.00
12.04	12.61	12.23	12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.45	22.50	Book Value per sh	25.50
17.14	17.41	17.68	19.46	19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.75	28.00	Common Shs Outst'g C	29.00
9.8	10.2	28.1	27.0	12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.5
.74	.76	1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.89	estimates		Relative P/E Ratio	.95
6.9%	6.7%	5.9%	5.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%			Avg Ann'l Div'd Yield	4.1%

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
356.3	380.3	361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	900	950	Revenues ($mill)	1100
38.1	46.8	43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	59.5	63.0	Net Profit ($mill)	80.0
36.8%	36.9%	32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	35.0%	35.0%	Income Tax Rate	35.0%
10.7%	12.3%	11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.6%	6.6%	Net Profit Margin	7.3%
43.5%	41.4%	46.0%	45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	45.5%	45.0%	Long-Term Debt Ratio	46.0%
50.3%	52.8%	49.0%	50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	54.5%	55.0%	Common Equity Ratio	54.0%
643.3	657.4	748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	1100	1150	Total Capital ($mill)	1360
697.2	745.3	827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	1350	1400	Net Plant ($mill)	1625
7.7%	8.9%	7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	7.0%	7.0%	Return on Total Cap'l	8.0%
10.5%	12.1%	10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	10.0%	10.5%	Return on Shr. Equity	10.5%
10.9%	12.7%	11.0%	6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	10.0%	10.5%	Return on Com Equity	10.5%
3.0%	5.0%	3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	4.5%	4.5%	Retained to Com Eq	4.5%
74%	63%	70%	118%	74%	70%	67%	79%	72%	69%	62%	62%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 9/30/05
Total Debt $602.0 mill. **Due in 5 Yrs** $160.0 mill.
LT Debt $521.5 mill. **LT Interest** $33.0 mill.
Incl. $5.6 mill. 7¼% debs. due 3/1/12, each conv. into 50.25 com. shs. at $19.90.
(Total interest coverage: 3.2x)

Pension Assets-12/04 $168.3 mill. **Oblig.** $205.4 mill.
Pfd Stock None

Common Stock 27,549,733 shs. as of 10/31/05
MARKET CAP $950 million (Small Cap)

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	4.7	5.2	3.4
Other	194.8	231.9	201.8
Current Assets	199.5	237.1	205.2
Accts Payable	86.0	102.5	81.7
Debt Due	85.2	117.5	80.5
Other	43.2	47.3	56.3
Current Liab.	214.4	267.3	218.5
Fx. Chg. Cov.	280%	316%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	8.0%	7.5%
"Cash Flow"	1.0%	1.5%	5.0%
Earnings	2.5%	3.0%	8.0%
Dividends	1.0%	1.0%	4.5%
Book Value	4.0%	3.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	278.6	101.9	78.7	182.2	641.4
2003	206.5	117.5	69.5	217.8	611.3
2004	254.5	109.7	81.4	262.0	707.6
2005	308.7	153.7	106.7	330.9	900
2006	350	175	125	300	950

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.32	d.13	d.26	.69	1.62
2003	1.01	.17	d.25	.83	1.76
2004	1.24	d.03	d.30	.95	1.86
2005	1.43	.04	d.31	.99	2.15
2006	1.50	.02	d.31	1.04	2.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.31	.31	.31	.315	1.25
2002	.315	.315	.315	.315	1.26
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	

BUSINESS: Northwest Natural Gas Co. (doing business as NW Natural) distributes natural gas at retail to 90 communities, 596,000 customers, in Oregon (96% of revs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.4 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system to bring gas to market. Owns local underground storage. Rev. breakdown: resident'l & comm'l, 84%; ind., 10%; transport. and other, 6%. Employs 1,291. Has abt 9,200 com. shrhldrs. Insiders own about 1% of com. (4/05 proxy). CEO: Mark S. Dodson. Inc.: OR. Addr.: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Web: www.nwnatural.com.

Northwest Natural's third-quarter loss was about as expected, despite a considerable increase in revenues and cost of gas. Gross profit rose about $5 million, due largely to price hikes, as residential, commercial, and firm industrial gas volumes were virtually unchanged from the prior-year period. Profits from interstate gas storage contributed $0.06 a share in 2005, due to the completion of the South Mist Pipeline Extension, compared with $0.02 in 2004. Notably, bad debt expense remained at a low level of half a percent of revenues, despite higher gas bills. During the September quarter, the Oregon Public Utility Commission renewed the company's "conservation" tariff for another four years and raised its coverage from 90% to 100% of residential and commercial volumes. The mechanism largely decouples earnings from gas volumes sold.
We look for a more normal share-net gain over the next year. Northwest's weather adjustment rate mechanism (WARM) added $0.18 a share to first-quarter 2005 earnings, so we do not anticipate a similar gain in 2006. But the company added 3.4% more gas customers in the 12 months ended September 30th, and they should contribute to the bottom line in 2006. The storage business will likely add a few cents a share. too. Importantly, Northwest had bought most of its gas for the current heating season by August 1st; that should limit the average increase in residential bills to around 15%, which is well below the national average forecast increase. As a result, we do not expect industrial gas volumes to suffer.
Earnings will probably grow slightly faster than the industry average. Northwest has raised its customer count at more than 3% per year for 19 years, and we see no reason why that should change. The company has enough good new customer prospects (on or near its mains) to potentially raise its count by over 40%. And NWN has borrowing capacity to fund acquisitions, should a neighboring utility come on the market.
These top-quality shares have some appeal to conservative accounts at their recent price. The stock is down from its recent high, and we think annual dividend hikes will continue.

Sigourney B. Romaine *December 16, 2005*

(A) Diluted earnings per share. Excludes nonrecurring gain: '98, $0.15; '00, $0.11. Next earnings report due early February.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Div'd reinvestment plan available.
(C) In millions, adjusted for stock split.

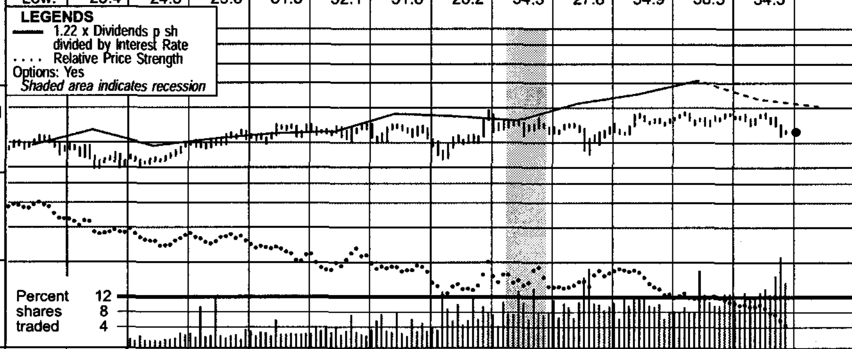
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	70

PEOPLES ENERGY NYSE-PGL

RECENT PRICE 36.44 | P/E RATIO 15.6 (Trailing: 16.1 / Median: 14.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 6.0% | VALUE LINE

TIMELINESS 5 Lowered 11/11/05
SAFETY 1 Raised 9/29/95
TECHNICAL 3 Raised 7/8/05
BETA .85 (1.00 = Market)

High:	32.1	32.0	37.4	39.9	40.1	40.3	46.9	44.6	40.4	45.3	46.0	45.5
Low:	23.4	24.3	29.6	31.3	32.1	31.8	26.2	34.3	27.8	34.9	38.5	34.3



Target Price Range 2008 | 2009 | 2010
120 100 80 64 48 32 24 20 16 12 8

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+65%)	18%
Low	45	(+25%)	11%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	0	0	0	0	0
Options	0	2	0	0	0	0	0	0	0
to Sell	0	3	0	0	0	0	0	0	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	94	94	105
to Sell	73	79	66
Hld's(000)	19746	22022	21808

% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	-15.3	10.4
3 yr.	14.8	74.6
5 yr.	11.7	81.1

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
36.42	35.63	33.69	31.54	36.09	36.70	29.60	34.29	36.34	32.28	33.66	40.16	64.13	41.81	58.28	59.90	68.40	72.50	Revenues per sh A	88.55
3.92	3.74	3.73	3.67	3.85	3.99	3.68	4.98	4.92	4.44	4.74	5.58	5.84	5.59	5.88	5.32	5.20	5.55	"Cash Flow" per sh	7.15
2.39	2.07	2.05	2.06	2.11	2.13	1.78	2.96	2.81	2.25	2.39	2.71	3.16	2.80	2.87	2.18	2.26	2.40	Earnings per sh B	3.10
1.58	1.65	1.71	1.76	1.78	1.80	1.80	1.82	1.87	1.91	1.95	2.00	2.04	2.07	2.12	2.16	2.18	2.20	Div'ds Decl'd per sh C ■	2.32
4.15	3.15	3.10	3.40	3.77	2.50	2.75	2.45	2.55	4.05	6.45	7.02	7.52	5.66	5.10	5.02	4.45	4.75	Cap'l Spending per sh	6.55
16.20	16.61	16.95	17.72	18.02	18.39	18.38	19.49	20.43	21.03	21.66	22.02	22.76	22.74	23.11	23.06	21.05	21.45	Book Value per sh D	25.85
32.62	32.70	32.76	34.77	34.88	34.87	34.91	34.96	35.07	35.26	35.49	35.30	35.40	35.46	36.69	36.69	38.00	38.00	Common Shs Outst'g E	35.00
7.9	11.2	11.8	13.1	15.0	13.3	14.7	10.7	12.7	16.2	15.5	12.1	12.3	13.3	13.4	19.1	18.9		Avg Ann'l P/E Ratio	17.0
.60	.83	.75	.79	.89	.87	.98	.67	.73	.84	.88	.79	.63	.73	.76	1.02	.99		Relative P/E Ratio	1.15
8.4%	7.1%	7.0%	6.5%	5.6%	6.3%	6.9%	5.7%	5.2%	5.2%	5.3%	6.1%	5.2%	5.5%	5.5%	5.2%	5.1%		Avg Ann'l Div'd Yield	4.4%

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1033.4	1198.7	1274.4	1138.1	1194.4	1417.5	2270.2	1482.5	2138.4	2260.2	2599.6	2755	Revenues ($mill) A	3100
62.2	103.4	98.4	79.4	84.8	96.1	111.7	99.3	103.9	81.6	86.2	90.0	Net Profit ($mill)	110
34.4%	37.6%	36.4%	36.2%	35.9%	34.1%	35.4%	34.2%	36.3%	31.7%	36.4%	36.0%	Income Tax Rate	35.5%
6.0%	8.6%	7.7%	7.0%	7.1%	6.8%	4.9%	6.7%	4.9%	3.6%	3.3%	3.3%	Net Profit Margin	3.5%
49.2%	43.6%	42.4%	41.1%	40.4%	35.1%	44.4%	40.7%	46.7%	50.8%	52.8%	52.0%	Long-Term Debt Ratio	49.5%
50.8%	56.4%	57.6%	58.9%	59.6%	64.9%	55.6%	59.3%	53.3%	49.2%	47.2%	48.0%	Common Equity Ratio	50.5%
1263.6	1208.3	1243.5	1258.0	1290.5	1196.7	1449.8	1360.3	1592.3	1767.5	1695.7	1705	Total Capital ($mill)	1795
1373.1	1381.1	1402.2	1446.7	1519.8	1645.3	1753.9	1773.9	1838.2	1904.2	1947.3	2000	Net Plant ($mill)	2105
7.0%	10.3%	9.5%	7.8%	8.0%	9.5%	9.3%	8.4%	8.1%	6.0%	6.6%	6.5%	Return on Total Cap'l	7.5%
9.7%	15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	10.8%	11.0%	Return on Shr. Equity	12.0%
9.7%	15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	10.8%	11.0%	Return on Com Equity	12.0%
NMF	5.9%	4.7%	1.7%	2.1%	3.4%	5.0%	3.3%	3.4%	.2%	.4%	1.0%	Retained to Com Eq	3.0%
101%	61%	66%	84%	81%	73%	64%	73%	73%	97%	96%	93%	All Div'ds to Net Prof	74%

CAPITAL STRUCTURE as of 6/30/05

Total Debt $912.3 mill. Due in 5 Yrs $315.0 mill.

LT Debt $897.1 mill. LT Interest $50.0 mill.
(Total interest coverage: 4.7x)

Pension Assets-9/04 $544.9 mill. Oblig. $515.8 mill.

Pfd Stock None

Common Stock 38,139,661 shs. as of 7/29/05

MARKET CAP: $1.4 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2003	2004	6/30/05
Cash Assets	33.0	21.1	100.0
Other	457.1	531.3	509.9
Current Assets	490.1	552.4	609.9
Accts Payable	236.6	144.7	163.5
Debt Due	207.9	55.6	15.2
Other	156.1	335.8	392.4
Current Liab.	600.6	536.1	571.1
Fix. Chg. Cov.	259%	304%	388%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.0%	10.0%	9.0%
"Cash Flow"	4.5%	4.0%	4.0%
Earnings	3.5%	2.0%	3.0%
Dividends	1.5%	2.0%	1.5%
Book Value	2.5%	2.5%	2.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	377.5	522.8	347.1	235.1	1482.5
2003	549.2	903.8	398.1	287.3	2138.4
2004	604.9	927.0	401.1	327.1	2260.2
2005	737.4	1026.9	455.9	379.4	2599.6
2006	805	1115	465	370	2755

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.87	1.55	.33	.05	2.80
2003	.87	1.77	.22	.04	F 2.87
2004	.85	1.46	.15	d.27	F 2.18
2005	.77	1.37	.18	d.06	2.26
2006	.79	1.38	.22	.01	2.40

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.50	.51	.51	.51	2.03
2002	.51	.52	.52	.52	2.07
2003	.53	.53	.53	.53	2.12
2004	.54	.54	.54	.54	2.16
2005	.545	.545	.545	.545	

BUSINESS: Peoples Energy Corporation distributes natural gas via its utility subsidiaries, Peoples Gas Light & Coke Co. (approx. 1,000,000 customers at 9/30/04) and North Shore Gas Co. (150,000), in Chicago and northeastern Illinois. Fiscal 2004 volume: 229 bill. cu. ft.: residential, 51%; commercial, 9%; industrial, 2%; other, 38%. Main supplier is Natural Gas Pipeline Co. of America. Purchased gas costs and revenue taxes accounted for 67% of gas revenues in fiscal '04. *Depreciation rate: 3.5%. Est'd plant age: 10 years.* Has 2,400 employees, 20,988 shareholders. Directors own 1% of common (1/05 Proxy). Chairman and CEO: Thomas M. Patrick. Inc.: Illinois. Address: 130 East Randolph Drive, Chicago, IL 60601. Telephone: 312-240-4000. Internet: www.pecorp.com.

Fiscal 2005 (ended September 30th) was not the best year for Peoples Energy. For the full year, operating results for the core gas distribution business were negatively impacted by an 5% decline in gas deliveries, to 218 billion cubic feet. This resulted in a $7 million dip in operating income for the division. Deliveries fell due to a combination of warmer weather, lower average use per customer, and a decrease in customer count. Indeed, weather for the year was 9% warmer than normal and 4% warmer than last year. Higher pension and bad debt expenses didn't help matters either. We believe that bad debt expenses and conservation could prove worse than management presently anticipates this fiscal year, which will depress earnings. Peoples is filing rate cases this January for its two utilities, seeking a total of $90-115 million that would become effective at the beginning of 2007. Meanwhile,

Production in the Oil and Gas segment continues to fall. Overall production declined nearly 12% in fiscal 2005. Management once again cited ongoing timing delays with the company's drilling program, in addition to well performance issues, pipeline curtailments, and equipment downtime. Peoples' production segment was again overly hedged in the September quarter and suffered $7.7 million in mark-to-market losses.

We have lowered our share earnings estimate for fiscal 2006 by $0.30, to $2.40. This is near the upper end of management's reduced target range. The full weight of rate relief and the expiration of profit-crimping hedges may not help until fiscal 2007. At this level of earnings, the company's payout ratio stands dangerously close to 95%, a level we feel is unsustainable over the long haul. This leads us to wonder whether dividend increases will be slow to come in the future. Non core operations have not been enough to cover the faltering gas distribution business. That said, we believe the dividend is safe for now, though we expect management might choose to halt quarterly increases, or keep them to one-half cent per share, rather than the one cent gains shareholders were used to in the past. Peoples stock is untimely.

Edward Plank *December 16, 2005*

(A) Fiscal year ends Sept. 30th.
(B) Basic earnings per share. Excludes acct'g gains/(losses): '89, $0.30; '99, $0.22; '00, ($0.27). Next earnings report due late Jan.
(C) Dividends historically paid mid-January, April, July, October. ■ Dividend reinvestment plan available.
(D) Includes deferred charges. At 9/30/04: $74.0 mill., $1.96/sh.
(E) In millions.
(F) Earnings don't sum due to change in shares outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	80

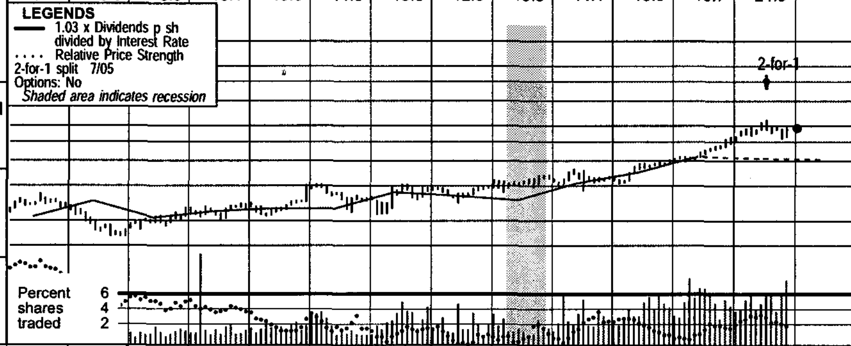
SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE **29.32** | P/E RATIO **15.1** (Trailing: 16.0 / Median: 13.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **3.2%** | VALUE LINE

TIMELINESS 3 Raised 8/12/05
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Lowered 8/5/05
BETA .65 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	12.0	11.8	12.3	15.3	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4
Low:	8.3	8.9	10.1	10.5	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9

LEGENDS
— 1.03 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded area indicates recession



Target Price Range
2008 | 2009 | 2010

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	8%
Low	25	(-15%)	Nil

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	1	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	3	0	2	1	0	1	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	31	54	55
to Sell	51	35	42
Hld's(000)	12752	15608	12984

Percent shares traded 6 4 2

% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	15.3	10.4
3 yr.	97.5	74.6
5 yr.	140.8	81.1

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
15.27	14.40	15.10	16.67	17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	**31.35**	**32.75**	Revenues per sh	**36.45**
1.50	1.34	1.37	1.56	1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	**2.75**	**2.95**	"Cash Flow" per sh	**3.30**
.83	.67	.64	.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	**1.87**	**2.00**	Earnings per sh A	**2.20**
.68	.70	.71	.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	**.86**	**.93**	Div'ds Decl'd per sh B ■	**1.10**
2.27	2.11	2.17	1.69	1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	**3.20**	**3.80**	Cap'l Spending per sh	**3.25**
6.74	6.79	6.77	6.95	7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	**13.65**	**15.10**	Book Value per sh C	**18.90**
16.96	18.06	18.48	19.00	19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	**28.70**	**29.00**	Common Shs Outst'g D	**31.00**
11.9	13.6	14.5	13.2	15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
.90	1.01	.93	.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.75	*Value Line*		Relative P/E Ratio	**.95**
6.9%	7.7%	7.6%	6.6%	5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	*estimates*		Avg Ann'l Div'd Yield	**3.6%**

CAPITAL STRUCTURE as of 9/30/05
Total Debt $392.9 mill. **Due in 5 Yrs** $58.5 mill.
LT Debt $319.1 mill. **LT Interest** $20.5 mill.
(Total interest coverage: 5.0x)

Pension Assets-12/04 $107.5 mill. **Oblig.** $100.5 mill.

Pfd Stock none

Common Stock 28,703,549 common shs. **(as of 11/8/05)**

MARKET CAP: $850 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
353.8	355.5	348.6	450.2	392.5	515.9	837.3	505.1	696.8	819.1	**900**	**950**	Revenues ($mill)	**1130**
17.8	18.5	18.4	13.8	22.0	24.7	26.8	29.4	34.6	43.0	**53.0**	**58.0**	Net Profit ($mill)	**70.0**
34.4%	35.5%	36.8%	46.2%	42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	**40.5%**	**40.5%**	Income Tax Rate	**40.5%**
5.0%	5.2%	5.3%	3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	**5.9%**	**6.1%**	Net Profit Margin	**6.2%**
51.4%	46.1%	54.6%	57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	**49.0%**	**49.0%**	Long-Term Debt Ratio	**48.0%**
47.9%	53.2%	35.8%	33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	**51.0%**	**51.0%**	Common Equity Ratio	**52.0%**
328.4	324.8	387.1	401.1	405.9	443.5	516.2	512.5	608.4	675.0	**770**	**850**	Total Capital ($mill)	**1135**
422.7	423.9	456.5	504.3	533.3	562.2	607.0	666.6	748.3	799.9	**860**	**940**	Net Plant ($mill)	**1120**
7.8%	7.9%	6.7%	5.3%	7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	**8.0%**	**8.0%**	Return on Total Cap'l	**7.0%**
11.2%	10.5%	10.5%	8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	**13.5%**	**13.0%**	Return on Shr. Equity	**11.5%**
11.2%	10.6%	13.3%	10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	**13.5%**	**13.0%**	Return on Com Equity	**11.5%**
1.4%	1.6%	2.1%	NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	**7.0%**	**7.0%**	Retained to Com Eq	**6.0%**
88%	85%	84%	112%	72%	67%	76%	62%	57%	52%	**47%**	**47%**	All Div'ds to Net Prof	**51%**

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	4.4	5.3	6.7
Other	261.4	278.6	287.8
Current Assets	265.8	283.9	294.5
Accts Payable	80.3	118.8	136.7
Debt Due	118.1	97.6	73.8
Other	70.1	68.9	113.4
Current Liab.	268.5	285.3	323.9
Fix. Chg. Cov.	378%	427%	445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	7.0%	*6.0%*
"Cash Flow"	4.5%	7.0%	*6.5%*
Earnings	6.5%	10.5%	*8.0%*
Dividends	1.0%	1.5%	*6.0%*
Book Value	4.5%	11.5%	*9.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	177.0	84.2	69.1	174.8	505.1
2003	279.9	106.2	90.1	220.6	696.8
2004	307.6	136.5	129.5	245.5	819.1
2005	328.5	154.0	157.0	**260.5**	**900**
2006	**340**	**170**	**165**	**275**	**950**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.83	.03	d.14	.50	1.22
2003	.92	.08	d.07	.44	1.37
2004	.91	.15	.02	.50	1.58
2005	.96	.27	.09	**.55**	**1.87**
2006	**1.00**	**.30**	**.13**	**.57**	**2.00**

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.182	.185	.185	.185	.74
2002	.185	.188	.188	.38	.94
2003	--	.193	.193	.395	.78
2004	--	.202	.202	.415	.82
2005	--	.213	.213	.438	

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 314,000 customers in New Jersey's southern counties, which cover 2,500 square miles and include Atlantic City. Principal suppliers include Transcontinental Gas Pipeline and Columbia Gas Pipeline. Gas revenue mix '04: residential, 31%; commercial and industrial, 10%; transportion, including off-system sales and gas marketing, 54%; off-system, 4%; cogeneration & power generation, 1%. Has 643 employees. Offs./dirs. cntrl. 1.4% of com. shares; Dimensional Fund Advisors, 7.4% (3/05 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Rte. 54, Folsom, NJ 08037. Telephone: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries is on pace for another good year in 2005. It reported earnings of $37.1 million over the first *nine months*, up nearly 30% from the year-ago period. These results were driven by strong profits at the company's utility segment, along with an expanding nonregulated division (discussed below). Over the last 12 months, South Jersey Gas added 9,068 customers, representing a near 3% growth rate, well above the national average. Coupled with a strong housing market in South Jersey, profits in this unit will likely expand at a nice pace over the 2008–2010 period.

The company expects to make significant additions to its reserves for bad debt. This is due to the projected high natural gas prices this winter, which would result in higher heating bills, and the likelihood of customers being unable to afford these costs. South Jersey will take measures to promote budget billing options and low-income assistance programs.

South Jersey is experiencing solid growth from its nonregulated businesses. So far this year, the segment has contributed $12 million to earnings, 43% above last year's tally. The Marina Energy unit should experience additional growth in the next few years, thanks to expansion projects under way. This includes the development of a landfill gas-to-electric power generation facility in Warren Country, along with the expansion of its Atlantic City thermal electric plant to support the scheduled 500,000-square-foot expansion at the Borgata Hotel Casino & Spa. Profits from appliance services should rise, too, as penetration in the residential market is expanded and service in the commercial market is initiated.

The company has implemented an early retirement program. This would provide South Jersey with significant future cost savings in the payroll, healthcare benefits, and pension areas.

South Jersey is a good-quality equity. However, its dividend yield is below that of the average natural gas distributor covered in *The Value Line Investment Survey.* Over the 3- to 5-year pull, we look for continued growth in the customer base, expansion in the nonutility sector, and above-average dividend increases.

Evan I. Blatter *December 16, 2005*

(A) Based on avg. shs. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops.: '96, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.01). Excl. gain due to acct'g change: '93, $0.04; '01, $0.14. Next egs. report due late January.
(B) Dividends paid early Apr., Jul., Oct, and late Dec. ■ Div. reinvest. plan avail. (2% disc.).
(C) Incl. regulatory assets ($76.2 mill.): at 9/30/05, $2.65 per shr.
(D) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

SOUTHWEST GAS NYSE-SWX

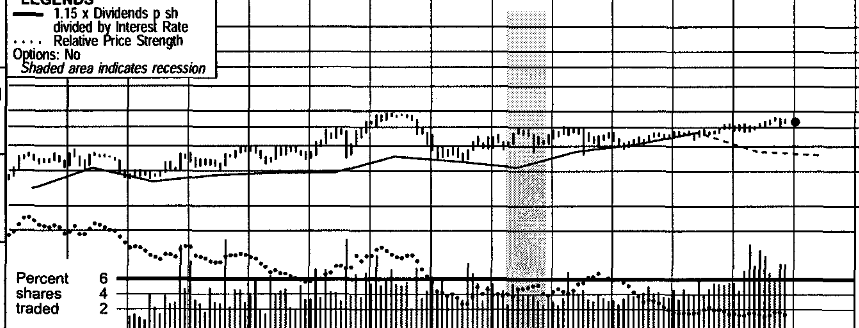
RECENT PRICE 26.65 | P/E RATIO 17.5 (Trailing: 16.6 Median: 20.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Raised 8/19/05
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Lowered 10/21/05
BETA .80 (1.00 = Market)

High:	19.4	18.4	19.9	20.3	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1
Low:	13.8	13.6	14.9	16.1	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5

Target Price Range 2008 | 2009 | 2010

LEGENDS
— 1.15 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+105%)	21%
Low	35	(+30%)	9%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	1	0	0	0	0
Options	0	0	1	1	1	4	0	5	7
to Sell	0	0	4	1	3	7	0	5	7

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	66	69	72
to Sell	45	45	46
Hld's(000)	22540	22886	26079

Percent shares traded 6 4 2

% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.4	10.4
3 yr.	33.4	74.6
5 yr.	63.4	81.1

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
25.71	25.90	24.99	25.93	25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	44.10	46.15	Revenues per sh A	47.00
4.10	3.96	1.53	3.34	3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.40	5.85	"Cash Flow" per sh	7.00
2.15	1.81	d.76	.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.40	1.65	Earnings per sh A B	2.45
1.39	1.40	.88	.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	Div'ds Decl'd per sh C■	.82
5.67	5.06	3.76	5.02	5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	6.40	6.40	Cap'l Spending per sh	6.25
17.30	17.63	15.88	15.99	15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.95	20.75	Book Value per sh	23.45
19.32	20.04	20.60	20.60	21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.00	39.00	Common Shs Outst'g D	41.50
8.5	8.7	--	16.6	26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	Bold figures are		Avg Ann'l P/E Ratio	18.0
.64	.65	--	1.01	1.57	.92	NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	Value Line		Relative P/E Ratio	1.20
7.6%	8.9%	7.0%	5.2%	4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	estimates		Avg Ann'l Div'd Yield	1.9%

CAPITAL STRUCTURE as of 9/30/05

Total Debt $1359.2 mill. Due in 5 Yrs $505.0 mill.
LT Debt $1249.2 mill. LT Interest $80.0 mill.
(Total interest coverage: 1.9x)

Pension Assets-12/04 $242.2 mill. Oblig. $319.4 mill.

Pfd Stock None

Common Stock 39,124,126 shs. (as of 11/1/05)

MARKET CAP: $1.0 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
563.5	644.1	732.0	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1720	1800	Revenues ($mill) A	1950
2.7	6.6	20.8	47.5	39.3	38.3	37.2	38.6	38.5	58.9	55.0	65.0	Net Profit ($mill)	100
24.0%	37.1%	29.2%	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	35.0%	35.0%	Income Tax Rate	31.0%
.5%	1.0%	2.8%	5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	3.1%	3.5%	Net Profit Margin	5.2%
65.2%	60.2%	63.6%	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	61.5%	60.5%	Long-Term Debt Ratio	56.0%
34.8%	34.4%	31.5%	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	38.5%	39.5%	Common Equity Ratio	44.0%
1024.0	1104.8	1224.7	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2030	2060	Total Capital ($mill) A	2225
1137.8	1278.5	1360.3	1459.4	1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2535	2720	Net Plant ($mill)	3295
2.7%	2.8%	3.9%	5.8%	4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.5%	5.0%	Return on Total Cap'l	6.5%
.7%	1.5%	4.7%	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	7.0%	8.0%	Return on Shr. Equity	10.5%
.7%	1.7%	5.4%	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	7.0%	8.0%	Return on Com Equity	10.5%
NMF	NMF	NMF	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	3.0%	4.0%	Retained to Com Eq	7.0%
NMF	NMF	107%	50%	64%	67%	71%	70%	72%	49%	58%	49%	All Div'ds to Net Prof	34%

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	17.2	13.6	16.9
Other	263.9	418.4	281.1
Current Assets	281.1	432.0	298.0
Accts Payable	110.1	165.9	97.6
Debt Due	58.4	129.8	110.0
Other	141.9	187.3	182.7
Current Liab.	310.4	483.0	390.3
Fix. Chg. Cov.	182%	166%	183%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	6.0%	3.5%
"Cash Flow"	3.0%	4.5%	6.0%
Earnings	4.0%	1.5%	10.5%
Dividends	1.0%	--	1.5%
Book Value	1.5%	4.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	499.5	261.1	223.9	336.4	1320.9
2003	403.3	255.8	220.2	351.7	1231.0
2004	473.4	278.7	264.5	460.5	1477.1
2005	542.9	361.1	313.3	502.7	1720
2006	565	390	330	515	1800

Cal-endar	EARNINGS PER SHARE B E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.14	d.35	d.49	.86	1.16
2003	.76	d.12	d.51	1.00	1.13
2004	1.18	d.24	d.51	1.23	1.66
2005	.88	d.07	d.43	1.02	1.40
2006	1.00	d.07	d.45	1.17	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.205	.205	.205	.205	.82
2002	.205	.205	.205	.205	.82
2003	.205	.205	.205	.205	.82
2004	.205	.205	.205	.205	.82
2005	.205	.205	.205	.205	

BUSINESS: *Southwest Gas Corporation is a regulated gas distributor serving approx. 1.6 million customers in sections of Arizona, Nevada, and California. '04 margin mix: resid. and small commercial, 83%; large commercial and industrial, 4%; transportation, 13%. Annual volume: 2.2 billion therms. Principal suppliers: El Paso Natural Gas Co. and Northwest Pipeline Corp. Acquired gas utility assets from Arizona Public Service in 1984. Sold PriMerit Bank (acq. in '86) in 7/96. Has about 2,550 employees, 22,990 shareholders. Officers & Directors own 1.8% of common (6/05 Proxy). Chairman.: Thomas Y. Hartley. CEO: Jeffrey W. Shaw. Incorporated: CA. Address: 5241 Spring Mountain Rd., P.O. Box 98510, Las Vegas, NV 89193-8510. Telephone: 702-876-7237. Internet: www.swgas.com.*

Southwest Gas had a stronger-than-expected third-quarter. Share loss of $0.43, was above our estimate of $0.55, and a solid improvement over last year. The company is finally beginning to see the results of its rate case initiatives bear fruit. Indeed, rate relief in Nevada and California, coupled with an incremental $4 million in gross margin from customer additions, accounted for the improvement.

The company is awaiting a rate-case decision in Arizona, which would mitigate the impact of weather on earnings and allow the company to recover its higher costs — all of which should benefit earnings going forward. Importantly, without the change in rate design, we think that Southwest's return on equity will continue to lag that of its peers. We suspect that Southwest will receive at least half of the $70.8 million it is seeking from the Arizona Corporation Commission (ACC). The proposed rate increase includes components designed to more closely tie the company's revenues to the fixed costs incurred in providing service. One proposed enhancement to the rate schedule is to shift more revenue into lower-usage periods and away from peak winter periods that depend on cold weather, which would reduce SWX's exposure to potentially warmer-than-normal temperatures. A decision is expected in early 2006.

During the last twelve months, Southwest added a record 79,000 customers. Typically, this pace of customer growth, while impressive, has been a doubled-edged sword for the company, given the implicit costs associated with such rapid expansion, but the improved rate structure is helping to ease the burden.

Southwest shares are not a standout. The company's balance sheet remains fairly highly leveraged, and higher interest rates have raised the cost of SWX's variable-rate debt. Plus, since dividend payments have not expanded in almost a decade, SWX shares are not all that appealing as an income vehicle. At about 3%, the dividend yield remains decent, but we think investors may want to look elsewhere for now. While we feel that the utility is showing signs of stabilizing earnings, a favorable award from the ACC is key to the long-term story here.

Edward Plank *December 16, 2005*

(A) Incl. income for PriMerit Bank on the equity basis through 1994.
(B) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢). Incl. asset writedown: '86, 9¢; '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Next egs. report due late January.
(C) Dividends historically paid early March, June, September, December.
■ Div'd reinvest. plan avail. (D) In millions.
(E) Quarters may not sum due to change in shares outstanding.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

WGL HOLDINGS NYSE-WGL

RECENT PRICE **30.62** | P/E RATIO **15.0** (Trailing: 14.5 Median: 14.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **4.4%** | **VALUE LINE**

High:	21.3	22.4	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8
Low:	16.0	16.1	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8

TIMELINESS 5 Lowered 9/2/05

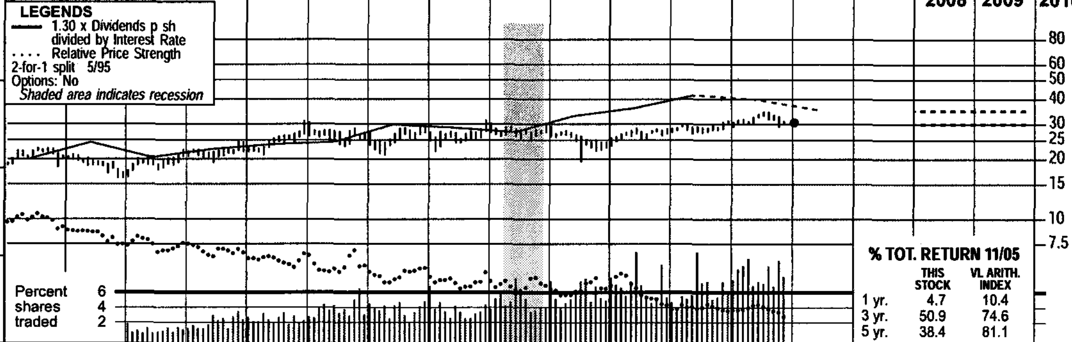
SAFETY 1 Raised 4/2/93

TECHNICAL 3 Lowered 8/12/05

BETA .80 (1.00 = Market)

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/95
Options: No
Shaded area indicates recession

Target Price Range 2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+15%)	7%
Low	30	(Nil)	4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	1	0
to Sell	0	0	0	0	1	0	0	1	0

Institutional Decisions

	1Q2005	2Q2005	3Q2005
to Buy	92	96	97
to Sell	62	63	65
Hld's(000)	26169	27756	27169

Percent shares traded 6 4 2

% TOT. RETURN 11/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	4.7	10.4
3 yr.	50.9	74.6
5 yr.	38.4	81.1

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
19.52	18.75	17.50	18.37	21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.89	46.70	Revenues per sh A	54.00
2.03	2.17	2.04	2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	4.00	4.00	"Cash Flow" per sh	4.70
1.22	1.26	1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	1.90	Earnings per sh B	2.40
.97	1.01	1.05	1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.34	Div'ds Decl'd per sh C ■	1.43
3.00	2.38	2.05	2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.55	4.10	Cap'l Spending per sh	2.55
9.86	10.17	9.63	10.66	11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.65	Book Value per sh D	21.75
38.70	39.23	39.89	40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.70	48.70	Common Shs Outst'g E	48.80
10.6	11.7	12.8	13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.8		Avg Ann'l P/E Ratio	14.0
.80	.87	.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.77		Relative P/E Ratio	.95
7.5%	6.9%	7.2%	6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%		Avg Ann'l Div'd Yield	4.3%

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
828.7	969.8	1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2275	Revenues ($mill) A	2635
62.9	81.6	82.0	68.6	68.8	84.6	89.9	55.7	112.3	98.0	104.8	98.0	Net Profit ($mill)	120
37.4%	37.7%	36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	38.0%	38.0%	Income Tax Rate	38.0%
7.6%	8.4%	7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	4.3%	Net Profit Margin	4.6%
37.8%	37.6%	41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	38.8%	38.0%	Long-Term Debt Ratio	37.0%
58.9%	59.4%	56.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	59.4%	60.5%	Common Equity Ratio	61.0%
870.6	941.1	1049.0	1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1507.7	1555	Total Capital ($mill)	1780
1056.1	1130.6	1217.1	1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2120	Net Plant ($mill)	2495
8.7%	10.1%	9.3%	8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	7.0%	6.5%	Return on Total Cap'l	7.0%
11.6%	13.9%	13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.5%	10.5%	Return on Shr. Equity	10.5%
12.0%	14.4%	13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	11.5%	10.5%	Return on Com Equity	11.0%
2.8%	5.6%	5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.5%	3.5%	Retained to Com Eq	4.5%
77%	62%	63%	78%	82%	69%	67%	112%	56%	65%	63%	67%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 9/30/05
Total Debt $675.2 mill. Due in 5 Yrs $330.0 mill.
LT Debt $584.2 mill. LT Interest $40.0 mill.
(LT interest earned: 4.7x; total interest coverage: 4.5x)
Pension Assets-9/04 $683.1 mill. Oblig. $655.8 mill.
Preferred Stock $28.2 mill. Pfd Div'd $1.3 mill.

Common Stock 48,704,000 shs.

MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2003	2004	9/30/05
Cash Assets	4.5	6.6	4.8
Other	404.4	426.3	476.2
Current Assets	408.9	432.9	481.0
Accts Payable	142.7	179.0	204.9
Debt Due	178.9	156.3	91.0
Other	64.5	77.6	115.5
Current Liab.	386.1	412.9	411.4
Fix. Chg. Cov.	487%	449%	460%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.5%	11.5%	5.5%
"Cash Flow"	4.5%	4.0%	5.0%
Earnings	3.0%	2.0%	5.0%
Dividends	1.5%	1.5%	2.0%
Book Value	4.0%	3.0%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	417.1	564.8	314.2	288.7	1584.8
2003	560.0	851.1	373.2	279.9	2064.2
2004	585.3	862.2	356.9	285.2	2089.6
2005	624.1	931.5	346.6	284.1	2186.3
2006	645	935	385	310	2275

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.66	1.09	d.14	d.47	1.14
2003	1.10	1.61	d.05	d.36	2.30
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	d.17	d.23	2.11
2006	.87	1.54	d.14	d.37	1.90

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.31	.315	.315	.315	1.26
2002	.315	.318	.318	.318	1.27
2003	.318	.32	.32	.32	1.28
2004	.32	.325	.325	.325	1.30
2005	.325	.333	.333	.333	

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA. and MD. to resident'l and comm'l users (1,012,105 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. Has 1,914 employees. Off./dir. own less than 1% of the common stock (1/05 proxy). Chairman & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Address: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL's fourth-quarter results (ended September 30th) were better than normal. This was due to higher profits in the nonregulated division, which reduced the typical seasonal losses experienced in the September period. Too, Maryland's weather normalization program now provides the company protection against revenue variations due to changes in usage caused by weather deviations and conservatism among customers. For 2006, WGL is targeting capital expenditures of about $200 million, a sharp increase over the $124 million in the previous year. This is due to costs associated with the rehabilitation occurring in the Prince George's County service area, along with the construction of an LNG peaking plant.

The company's service area is located *in one of the fastest-growing utility* markets in the country. Due to the affluence of the region, higher gas prices will continue to represent a small portion of the total income for many of these individuals. Therefore, Washington Gas will likely experience less of an increase in bad debt expense compared to other gas distributors. Long-term, the company continues to anticipate adding 25,000–30,000 new customers per year. This represents a 2.7% annual growth rate, nearly twice the national average.

The company's nonregulated business continues to expand. For fiscal 2005, the unit posted earnings of $16 million, nearly 93% above the year-ago period. The results comprised $22.3 million from the retail energy marketing segment, offset by a $3.9 million loss in the heating, ventilating, and air-conditioning segment (HVAC) and a $2.4 million loss in its other activities. Despite the HVAC shortfall, WGL will continue to operate the segment. The unit has value, since it is close to breaking even and would cost more to shut down. Moreover, the primary driver of the earnings advance in the marketing segment was due to higher gross margins in the sale of natural gas.

Though the stock is untimely, income-oriented investors may find it appealing. WGL has increased its dividend for 29 consecutive years, and we expect the streak to continue. The current yield is a respectable 4.4%.

Evan I. Blatter *December 16, 2005*

(A) Beginning 1989, fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢).
Next earnings report due late January.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '04: $156.5 million, $3.22/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	60

ATTACHMENT D

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AMERICAN STS WTR CO AWR (NYSE)

American States is a public utility company engaged principally in thepurchase, production, distribution and sale of water. The company alsodistributes electricity in some communities. In the customer service areas for both water and electric, rates and operations are subject to the jurisdiction of the California Public Utilities Commission.

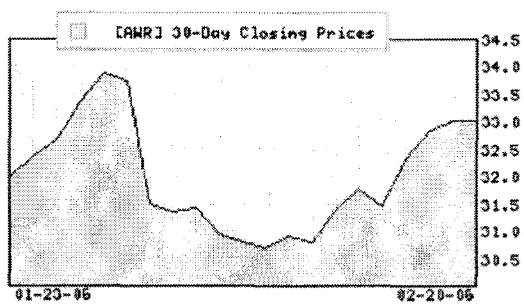
General Information

AMER STATES WTR
630 East Foothill Boulevard
San Dimas, CA 91773
Phone: 909 394-3600
Fax: 909 394-0711
Web: www.aswater.com
Email: investorinfo@aswater.com

Industry	UTIL-WATER SPLY
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	03/16/2006

Price and Volume Information

Zacks Rank	2
Yesterday's Close	33.02
52 Week High	34.06
52 Week Low	24.95
Beta	0.00
20 Day Moving Average	82,095
Target Price Consensus	35



% Price Change

4 Week	5.83
12 Week	5.39
YTD	7.21

% Price Change Relative to S&P 500

4 Week	5.86
12 Week	2.20
YTD	0.44

Share Information

Shares Outstanding (millions)	16.79
Market Capitalization (millions)	554.41
Short Interest (shares)	658,091
Short Ratio	13.07
Last Split Date	06/10/2002

Dividend Information

Dividend Yield	2.73%
Annual Dividend	$0.90
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	11/16/2005 / $0.22

EPS Information

Current Quarter EPS Consensus Estimate	0.21
Current Year EPS Consensus Estimate	1.06
Estimated Long-Term EPS Growth Rate	6.00

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.00
60 Days Ago	3.00

Next EPS Report Date	03/16/2006 90 Days Ago		3.00

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	22.85	vs. Previous Year	-9.62%	vs. Previous Year	-1.29%
Trailing 12 Months:	28.47	vs. Previous Quarter	38.24%	vs. Previous Quarter:	12.52%
PEG Ratio	3.81				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.19	12/31/05	-	12/31/05	-
Price/Cash Flow	22.80	09/30/05	7.68	09/30/05	2.37
Price / Sales	-	06/30/05	7.77	06/30/05	2.43
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	0.54	09/30/05	0.53	09/30/05	8.50
06/30/05	0.54	06/30/05	0.52	06/30/05	8.47
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	-	09/30/05	-	09/30/05	15.66
06/30/05	-	06/30/05	-	06/30/05	15.15
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	-	09/30/05	0.87	09/30/05	46.53
06/30/05	-	06/30/05	0.90	06/30/05	47.39

Zacks.com Quotes and Research

CALIFORNIA WTR SVC GROUP CWT (NYSE)

California Water Service Company's business, which is carried on through its operating subsidiaries, consists of the production, purchase, storage, purification, distribution and sale of water for domestic, industrial, public and irrigation uses, and for fire protection. It also provides water related services under agreements with municipalities and other private companies. The nonregulated services include full water system operation, and billing and meter reading services.

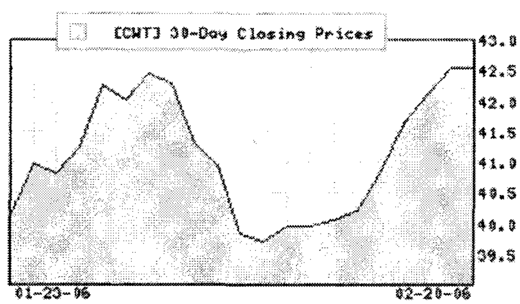
General Information

CALIF WATER SVC
1720 North First Street
San Jose, CA 95112
Phone: 408 367-8200
Fax: 408 437-9185
Web: www.calwater.com
Email: klichtenberg@calwater.com

Industry	UTIL-WATER SPLY
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	04/26/2006

Price and Volume Information

Zacks Rank	4
Yesterday's Close	42.53
52 Week High	42.53
52 Week Low	32.64
Beta	0.11
20 Day Moving Average	39,030
Target Price Consensus	41



% Price Change

4 Week	6.59
12 Week	16.36
YTD	11.25

% Price Change Relative to S&P 500

4 Week	6.62
12 Week	12.84
YTD	3.21

Share Information

Shares Outstanding (millions)	18.39
Market Capitalization (millions)	782.13
Short Interest (shares)	580,388
Short Ratio	18.20
Last Split Date	01/26/1998

Dividend Information

Dividend Yield	2.70%
Annual Dividend	$1.15
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	11/03/2005 / $0.28

EPS Information

Current Quarter EPS Consensus Estimate	0.12
Current Year EPS Consensus Estimate	1.69

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.40
30 Days Ago	2.50

Estimated Long-Term EPS Growth Rate	9.00	60 Days Ago	2.50
Next EPS Report Date	04/26/2006	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	25.14	vs. Previous Year	60.00%	vs. Previous Year	12.20%
Trailing 12 Months:	30.16	vs. Previous Quarter	-54.93%	vs. Previous Quarter:	-23.03%
PEG Ratio	2.79				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.66	12/31/05	9.41	12/31/05	2.80
Price/Cash Flow	13.98	09/30/05	8.74	09/30/05	2.62
Price / Sales	2.44	06/30/05	7.96	06/30/05	2.40
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	0.74	12/31/05	0.68	12/31/05	8.49
09/30/05	0.92	09/30/05	0.87	09/30/05	8.05
06/30/05	0.95	06/30/05	0.90	06/30/05	7.40
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	14.72	12/31/05	14.72	12/31/05	15.98
09/30/05	13.43	09/30/05	13.43	09/30/05	15.99
06/30/05	12.22	06/30/05	12.22	06/30/05	15.54
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	30.02	12/31/05	0.93	12/31/05	47.96
09/30/05	12.55	09/30/05	0.93	09/30/05	47.99
06/30/05	20.04	06/30/05	0.96	06/30/05	48.71

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SOUTHWEST WTR CO SWWC (NASDAQ)

Southwest Water Company provides a broad range of utility and utility management services and serves people from coast to coast. Through its various subsidiaries, Southwest operates and manages water and wastewater treatment facilities along with providing utility submetering and billing and collection services.

General Information

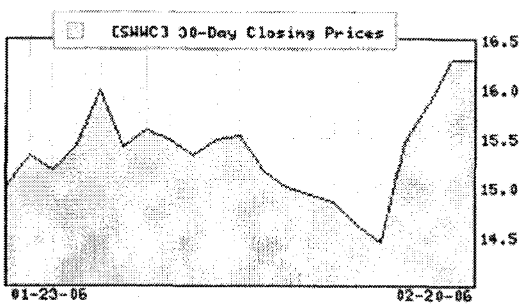
SOUTHWEST WATER
624 South Grand Avenue
Suite 2900
Los Angeles, CA 90017-3782
Phone: 213 929-1800
Fax: 213 929-1888
Web: www.southwestwater.com
Email: swwc@swwc.com

Industry	UTIL-WATER SPLY
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	03/14/2006

Price and Volume Information

Zacks Rank	3
Yesterday's Close	16.28
52 Week High	16.28
52 Week Low	9.43
Beta	0.31
20 Day Moving Average	100,828
Target Price Consensus	12.38



% Price Change

4 Week	9.04
12 Week	22.27
YTD	13.77

% Price Change Relative to S&P 500

4 Week	9.07
12 Week	18.57
YTD	2.17

Share Information

Shares Outstanding (millions)	21.53
Market Capitalization (millions)	350.46
Short Interest (shares)	1,084,866
Short Ratio	11.13
Last Split Date	12/27/2002

Dividend Information

Dividend Yield	1.35%
Annual Dividend	$0.22
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	12/28/2005 / $0.05

EPS Information

Current Quarter EPS Consensus Estimate	0.06
Current Year EPS Consensus Estimate	0.36

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.00
30 Days Ago	2.00

Estimated Long-Term EPS Growth Rate	5.50	60 Days Ago	2.00
Next EPS Report Date	03/14/2006	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	36.56	vs. Previous Year	21.15%	vs. Previous Year	-0.64%
Trailing 12 Months:	63.31	vs. Previous Quarter	0.00%	vs. Previous Quarter:	6.60%
PEG Ratio	6.65				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.63	12/31/05	-	12/31/05	-
Price/Cash Flow	24.08	09/30/05	4.26	09/30/05	1.30
Price / Sales	-	06/30/05	3.80	06/30/05	1.17
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	1.33	09/30/05	1.33	09/30/05	2.70
06/30/05	1.62	06/30/05	1.62	06/30/05	2.38
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	4.13	09/30/05	4.13	09/30/05	6.39
06/30/05	3.70	06/30/05	3.70	06/30/05	6.07
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	24.61	09/30/05	0.94	09/30/05	48.44
06/30/05	24.83	06/30/05	1.02	06/30/05	50.41

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AQUA AMERICA INC WTR (NYSE)

Aqua America is the largest publicly-traded U.S.-based water utility serving residents in Pennsylvania, Ohio, Illinois, Texas, New Jersey, Indiana, Virginia, Florida, North Carolina, Maine, Missouri, New York, South Carolina and Kentucky. The company has been committed to the preservation and improvement of the environment throughout its history, which spans more than 100 years.

General Information

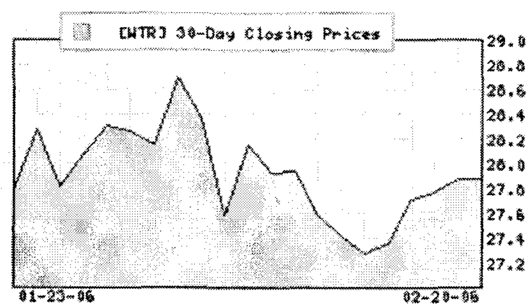
AQUA AMER INC
762 W. Lancaster Avenue
Bryn Mawr, PA 19010-3489
Phone: 610 527-8000
Fax: 610 519-0989
Web: www.aquaamerica.com
Email: investorrelations@aquaamerica.com

Industry	UTIL-WATER SPLY
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	03/09/2006

Price and Volume Information

Zacks Rank	2
Yesterday's Close	27.87
52 Week High	28.97
52 Week Low	17.79
Beta	0.00
20 Day Moving Average	350,700
Target Price Consensus	21.75



% Price Change

4 Week	-1.59
12 Week	5.42
YTD	2.09

% Price Change Relative to S&P 500

4 Week	-1.56
12 Week	2.22
YTD	-1.04

Share Information

Shares Outstanding (millions)	128.67
Market Capitalization (millions)	3,586.12
Short Interest (shares)	6,207,324
Short Ratio	16.47
Last Split Date	12/03/2001

Dividend Information

Dividend Yield	1.53%
Annual Dividend	$0.43
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	11/15/2005 / $0.11

EPS Information

Current Quarter EPS Consensus Estimate	0.18
Current Year EPS Consensus Estimate	0.72
Estimated Long-Term EPS Growth Rate	9.30

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.43
30 Days Ago	2.43
60 Days Ago	2.43

Next EPS Report Date	03/09/2006 90 Days Ago		2.43

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	34.89	vs. Previous Year	11.54%	vs. Previous Year	13.70%
Trailing 12 Months:	38.71	vs. Previous Quarter	26.09%	vs. Previous Quarter:	11.12%
PEG Ratio	3.77				
Price Ratios		**ROE**		**ROA**	
Price/Book	4.71	12/31/05	-	12/31/05	-
Price/Cash Flow	25.41	09/30/05	11.95	09/30/05	3.78
Price / Sales	-	06/30/05	11.83	06/30/05	3.71
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	0.39	09/30/05	0.36	09/30/05	18.70
06/30/05	0.36	06/30/05	0.32	06/30/05	18.54
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	30.80	09/30/05	30.80	09/30/05	6.09
06/30/05	30.50	06/30/05	30.50	06/30/05	6.05
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	0.00	09/30/05	1.10	09/30/05	52.32
06/30/05	0.00	06/30/05	1.09	06/30/05	52.24

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CASCADE NAT GAS CORP CGC (NYSE)

Cascade Natural Gas Corporation's principal business is the distribution of natural gas.

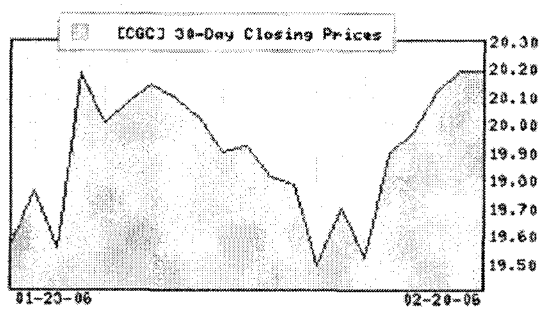
General Information

CASCADE NAT GAS
222 Fairview Avenue North
Seattle, WA 98109
Phone: 206 624-3900
Fax: 206 624-7215
Web: www.cngc.com
Email: investorinfo@cngc.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/05
Next EPS Date	04/20/2006

Price and Volume Information

Zacks Rank	4
Yesterday's Close	20.19
52 Week High	22.75
52 Week Low	18.49
Beta	0.09
20 Day Moving Average	51,525
Target Price Consensus	N/A



% Price Change

4 Week	2.54
12 Week	-0.83
YTD	3.49

% Price Change Relative to S&P 500

4 Week	2.57
12 Week	-3.84
YTD	-0.52

Share Information

Shares Outstanding (millions)	11.44
Market Capitalization (millions)	230.89
Short Interest (shares)	289,721
Short Ratio	8.49
Last Split Date	12/21/1993

Dividend Information

Dividend Yield	4.75%
Annual Dividend	$0.96
Payout Ratio	1.03
Change in Payout Ratio	0.10
Last Dividend Payout / Amount	01/27/2006 / $0.24

EPS Information

Current Quarter EPS Consensus Estimate	0.60
Current Year EPS Consensus Estimate	1.01
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	04/20/2006

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.00
60 Days Ago	3.00
90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.99	vs. Previous Year	11.11%	vs. Previous Year	51.64%
Trailing 12 Months:	21.71	vs. Previous Quarter	318.75%	vs. Previous Quarter:	231.44%
PEG Ratio	3.33				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.94	12/31/05	8.58	12/31/05	2.10
Price/Cash Flow	6.92	09/30/05	7.88	09/30/05	2.05
Price / Sales	0.61	06/30/05	8.40	06/30/05	2.35
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	0.99	12/31/05	0.93	12/31/05	2.80
09/30/05	1.00	09/30/05	0.90	09/30/05	2.99
06/30/05	0.91	06/30/05	0.73	06/30/05	3.25
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	4.52	12/31/05	4.52	12/31/05	10.88
09/30/05	4.55	09/30/05	4.55	09/30/05	10.42
06/30/05	5.19	06/30/05	5.19	06/30/05	11.02
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	26.66	12/31/05	1.33	12/31/05	57.12
09/30/05	20.55	09/30/05	1.47	09/30/05	59.44
06/30/05	20.40	06/30/05	1.27	06/30/05	55.94

ZACKS
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Zacks.com Quotes and Research

KEYSPAN CORP KSE (NYSE)

KeySpan Corporation provides a range of energy-related services through operations and investments in selected areas of the energy industry. The Company engages in four core downstream businesses: natural gas distribution, Electric Services, Energy Services and Energy Investments. It also competes in two additional lines of business: gas explorationand production and select energy-related investments.

General Information

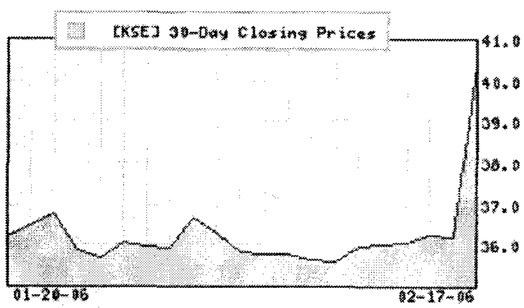
KEYSPAN CORP
175 East Old Country Road
Hicksville, NY 11801
Phone: 516 755-6650
Fax: -
Web: www.keyspanenergy.com
Email: boardofdirectors@keyspanenergy.com.

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	02/24/2006

Price and Volume Information

Zacks Rank	2
Yesterday's Close	40.41
52 Week High	40.99
52 Week Low	33.03
Beta	0.33
20 Day Moving Average	756,500
Target Price Consensus	36.53



% Price Change

4 Week	13.38
12 Week	18.85
YTD	13.23

% Price Change Relative to S&P 500

4 Week	13.42
12 Week	15.25
YTD	-0.70

Share Information

Shares Outstanding (millions)	174.36
Market Capitalization (millions)	7,045.93
Short Interest (shares)	5,753,098
Short Ratio	6.44
Last Split Date	07/21/1993

Dividend Information

Dividend Yield	4.60%
Annual Dividend	$1.86
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	01/10/2006 / $0.47

EPS Information

Current Quarter EPS Consensus Estimate	0.69
Current Year EPS Consensus Estimate	2.37
Estimated Long-Term EPS Growth Rate	3.10

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.78
30 Days Ago	2.78
60 Days Ago	2.80

Next EPS Report Date		02/24/2006 90 Days Ago			2.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.85	vs. Previous Year	1,200.00%	vs. Previous Year	24.05%
Trailing 12 Months:	15.54	vs. Previous Quarter	30.00%	vs. Previous Quarter:	-2.93%
PEG Ratio	5.39				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.67	12/31/05	-	12/31/05	-
Price/Cash Flow	6.47	09/30/05	10.16	09/30/05	3.31
Price / Sales	-	06/30/05	10.08	06/30/05	3.20
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	1.73	09/30/05	1.21	09/30/05	6.10
06/30/05	1.70	06/30/05	1.25	06/30/05	6.03
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	13.21	09/30/05	13.21	09/30/05	25.17
06/30/05	11.40	06/30/05	11.40	06/30/05	27.74
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	6.15	09/30/05	0.89	09/30/05	47.25
06/30/05	6.19	06/30/05	0.87	06/30/05	46.70

ZACKS
PROFIT FROM THE PROS

Zacks.com Quotes and Research

LACLEDE GROUP INC LG (NYSE)

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

General Information

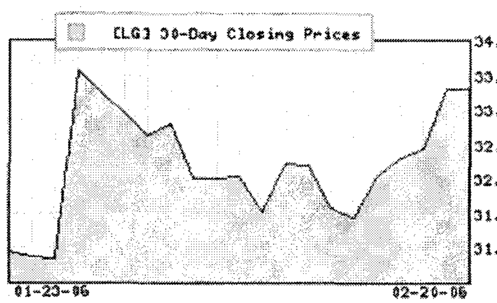
LACLEDE GRP INC
720 Olive Street
St. Louis, MO 63101
Phone: 314-342-0500
Fax: -
Web: www.thelacledegroup.com
Email: investorservices@lacledegas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	September
Last Reported Quarter	12/31/05
Next EPS Date	04/27/2006

Price and Volume Information

Zacks Rank	1
Yesterday's Close	33.30
52 Week High	33.99
52 Week Low	27.37
Beta	0.15
20 Day Moving Average	73,500
Target Price Consensus	36



% Price Change

4 Week	10.63
12 Week	11.48
YTD	14.00

% Price Change Relative to S&P 500

4 Week	10.66
12 Week	8.11
YTD	6.52

Share Information

Shares Outstanding (millions)	21.25
Market Capitalization (millions)	707.69
Short Interest (shares)	644,764
Short Ratio	12.45
Last Split Date	03/08/1994

Dividend Information

Dividend Yield	4.14%
Annual Dividend	$1.38
Payout Ratio	0.59
Change in Payout Ratio	-0.25
Last Dividend Payout / Amount	12/08/2005 / $0.34

EPS Information

Current Quarter EPS Consensus Estimate	1.12
Current Year EPS Consensus Estimate	2.27
Estimated Long-Term EPS Growth Rate	-

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.33
30 Days Ago	2.33
60 Days Ago	2.33

Next EPS Report Date		04/27/2006 90 Days Ago			2.33

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	15.49	vs. Previous Year	55.70%	vs. Previous Year	55.76%
Trailing 12 Months:	14.23	vs. Previous Quarter	612.50%	vs. Previous Quarter:	158.46%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.92	12/31/05	13.02	12/31/05	3.57
Price/Cash Flow	10.55	09/30/05	10.69	09/30/05	3.00
Price / Sales	0.38	06/30/05	10.57	06/30/05	3.01
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	1.01	12/31/05	0.73	12/31/05	2.69
09/30/05	1.16	09/30/05	0.66	09/30/05	2.51
06/30/05	1.08	06/30/05	0.78	06/30/05	2.58
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	4.01	12/31/05	4.01	12/31/05	18.47
09/30/05	3.81	09/30/05	3.81	09/30/05	17.33
06/30/05	3.88	06/30/05	3.88	06/30/05	18.20
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	12.21	12/31/05	0.87	12/31/05	46.38
09/30/05	10.94	09/30/05	0.93	09/30/05	48.09
06/30/05	11.07	06/30/05	0.89	06/30/05	46.92

ZACKS PROFIT FROM THE PROS

Zacks.com Quotes and Research

NORTHWEST NAT GAS CO NWN (NYSE)

NW Natural is principally engaged in the distribution of natural gas.The Oregon Public Utility Commission (OPUC) has allocated to NW Natural as its exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the fertile Willamette Valley and the coastal area from Astoria to Coos Bay. NW Natural also holds certificates from the Washington Utilities and Transportation Commission (WUTC) granting it exclusive rights to serve portions of three Washington counties bordering the Columbia River.

General Information

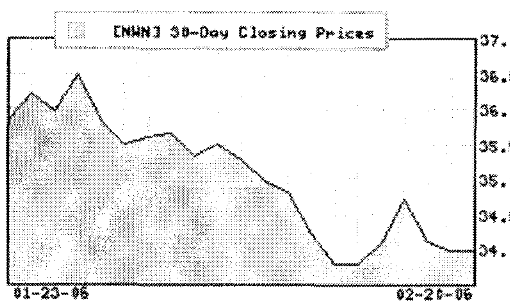
NORTHWEST NAT G
220 N.W. Second Avenue
Portland, OR 97209
Phone: 503 226-4211
Fax: 503 273-4824
Web: www.nwnatural.com
Email: investorinformation@nwnatural.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	04/28/2006

Price and Volume Information

Zacks Rank	2
Yesterday's Close	33.98
52 Week High	39.50
52 Week Low	33.75
Beta	0.06
20 Day Moving Average	121,875
Target Price Consensus	38.75



% Price Change

4 Week	-5.43
12 Week	-1.82
YTD	-0.59

% Price Change Relative to S&P 500

4 Week	-5.40
12 Week	-4.79
YTD	-2.57

Share Information

Shares Outstanding (millions)	27.55
Market Capitalization (millions)	936.15
Short Interest (shares)	1,085,795
Short Ratio	10.11
Last Split Date	09/09/1996

Dividend Information

Dividend Yield	4.06%
Annual Dividend	$1.38
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	01/27/2006 / $0.34

EPS Information

Current Quarter EPS Consensus Estimate	1.50
Current Year EPS Consensus Estimate	2.24

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.00
30 Days Ago	2.00

Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.50
Next EPS Report Date	04/28/2006	90 Days Ago	2.50

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	14.88	vs. Previous Year	-4.12%	vs. Previous Year	-60.15%
Trailing 12 Months:	16.26	vs. Previous Quarter	400.00%	vs. Previous Quarter:	134.99%
PEG Ratio	2.81				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.64	12/31/05	-	12/31/05	-
Price/Cash Flow	8.63	09/30/05	10.17	09/30/05	3.25
Price / Sales	1.53	06/30/05	10.35	06/30/05	3.47
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	0.94	09/30/05	0.49	09/30/05	7.70
06/30/05	1.09	06/30/05	0.76	06/30/05	7.41
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	11.86	09/30/05	11.86	09/30/05	20.69
06/30/05	11.38	06/30/05	11.38	06/30/05	21.48
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	8.13	09/30/05	0.91	09/30/05	47.76
06/30/05	8.85	06/30/05	0.88	06/30/05	46.84

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PEOPLES ENERGY CORP PGL (NYSE) Sponsored by: Scottrade $7 Trades

People's Energy Corporation is solely a holding company and does not engage directly in any business of its own. Income is derived principally from the company's utility subsidiaries, The Peoples Gas Light and Coke Company and North Shore Gas Company. The company also derives income from its other subsidiaries, Peoples District Energy Corporation, Peoples Energy Services Corporation, Peoples Energy Resources Corp., Peoples NGV Corp., and Peoples Energy Ventures Corporation.

General Information

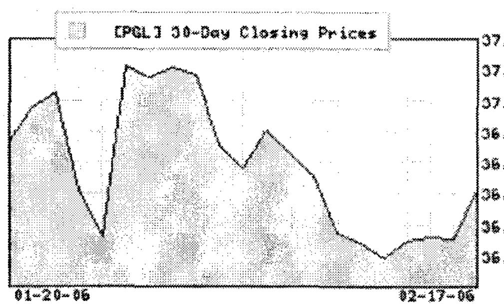
PEOPL ENERGY CP
130 East Randolph Drive
24th Floor
Chicago, IL 60601-6207
Phone: 312 240-4000
Fax: 312 240-7534
Web: www.peoplesenergy.com
Email: pecstock@pecorp.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	September
Last Reported Quarter	12/31/05
Next EPS Date	04/28/2006

Price and Volume Information

Zacks Rank	3
Yesterday's Close	36.43
52 Week High	45.42
52 Week Low	35.04
Beta	0.17
20 Day Moving Average	340,390
Target Price Consensus	38.5



% Price Change

4 Week	-0.46
12 Week	0.16
YTD	3.88

% Price Change Relative to S&P 500

4 Week	-0.44
12 Week	-2.87
YTD	1.36

Share Information

Shares Outstanding (millions)	38.27
Market Capitalization (millions)	1,394.32
Short Interest (shares)	3,631,574
Short Ratio	15.01
Last Split Date	N/A

Dividend Information

Dividend Yield	5.98%
Annual Dividend	$2.18
Payout Ratio	0.82
Change in Payout Ratio	0.04
Last Dividend Payout / Amount	12/20/2005 / $0.55

EPS Information

Current Quarter EPS Consensus Estimate	1.29
Current Year EPS Consensus Estimate	2.19

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.40
30 Days Ago	3.40

Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	3.33
Next EPS Report Date	04/28/2006	90 Days Ago	3.33

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.63	vs. Previous Year	20.78%	vs. Previous Year	42.71%
Trailing 12 Months:	13.64	vs. Previous Quarter	389.47%	vs. Previous Quarter:	177.43%
PEG Ratio	4.16				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.74	12/31/05	12.17	12/31/05	2.96
Price/Cash Flow	6.54	09/30/05	11.11	09/30/05	2.86
Price / Sales	0.48	06/30/05	10.53	06/30/05	2.86
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	1.04	12/31/05	1.03	12/31/05	3.51
09/30/05	1.00	09/30/05	0.72	09/30/05	3.68
06/30/05	1.07	06/30/05	0.83	06/30/05	3.62
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	1.77	12/31/05	1.77	12/31/05	20.96
09/30/05	4.72	09/30/05	4.72	09/30/05	20.98
06/30/05	4.20	06/30/05	4.20	06/30/05	23.14
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	13.83	12/31/05	1.12	12/31/05	52.74
09/30/05	10.88	09/30/05	1.12	09/30/05	52.81
06/30/05	11.35	06/30/05	1.02	06/30/05	50.49

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PROFIT FROM THE PROS

Zacks.com Quotes and Research

SOUTH JERSEY INDS INC SJI (NYSE)

South Jersey Inds Inc. is engaged in the business of operating, through subsidiaries, various business enterprises. The company's most significant subsidiary is South Jersey Gas Company (SJG). SJG is a public utility company engaged in the purchase, transmission and sale of natural gas for residential, commercial and industrial use. SJG also makes off-system sales of natural gas on a wholesale basis to various customers on the interstate pipeline system and transports natural gas.

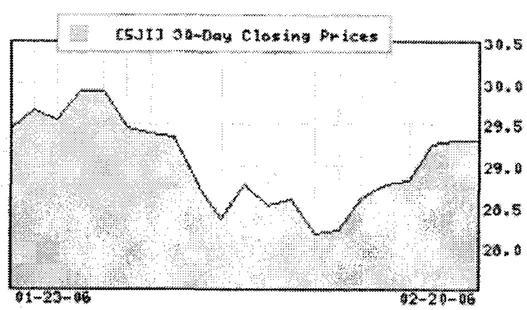
General Information

SOUTH JERSEY IN
1 South Jersey Plaza
Folsom, NJ 08037
Phone: 609 561-9000
Fax: 609-704-1608
Web: www.sjindustries.com
Email: investorrelations@sjindustries.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	02/28/2006

Price and Volume Information

Zacks Rank	4
Yesterday's Close	29.30
52 Week High	32.00
52 Week Low	26.49
Beta	0.25
20 Day Moving Average	83,350
Target Price Consensus	32



% Price Change

4 Week	-1.81
12 Week	9.37
YTD	0.55

% Price Change Relative to S&P 500

4 Week	-1.78
12 Week	6.06
YTD	-4.62

Share Information

Shares Outstanding (millions)	28.70
Market Capitalization (millions)	841.03
Short Interest (shares)	855,204
Short Ratio	9.04
Last Split Date	03/04/1993

Dividend Information

Dividend Yield	3.07%
Annual Dividend	$0.90
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	12/07/2005 / $0.22

EPS Information

Current Quarter EPS Consensus Estimate	N/A
Current Year EPS Consensus Estimate	1.75

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.67
30 Days Ago	2.67

Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.67
Next EPS Report Date	02/28/2006	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.10	vs. Previous Year	500.00%	vs. Previous Year	22.44%
Trailing 12 Months:	16.01	vs. Previous Quarter	-66.67%	vs. Previous Quarter:	1.90%
PEG Ratio	2.68				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.35	12/31/05	-	12/31/05	-
Price/Cash Flow	11.57	09/30/05	14.16	09/30/05	4.14
Price / Sales	-	06/30/05	13.84	06/30/05	4.10
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	0.91	09/30/05	0.52	09/30/05	5.79
06/30/05	0.97	06/30/05	0.64	06/30/05	5.73
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	9.81	09/30/05	9.81	09/30/05	13.03
06/30/05	9.67	06/30/05	9.67	06/30/05	13.15
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	8.66	09/30/05	0.87	09/30/05	46.45
06/30/05	9.00	06/30/05	0.87	06/30/05	46.49

ZACKS
PROFIT FROM THE PROS

Zacks.com Quotes and Research

SOUTHWEST GAS CORP SWX (NYSE)

SOUTHWEST GAS CORP. is principally engaged in the business of purchasing,transporting, and distributing natural gas in portions of Arizona, Nevada,and California. The Company also engaged in financial services activities,through PriMerit Bank, Federal Savings Bank (PriMerit or the Bank), a wholly owned subsidiary.

General Information

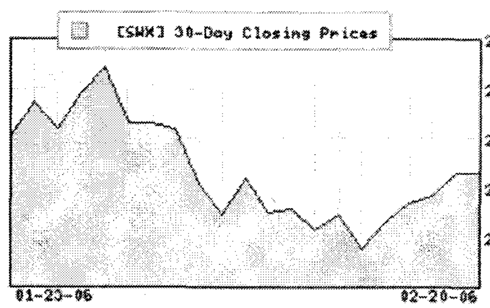
SOUTHWEST GAS
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, NV 89193-8510
Phone: 702 876-7237
Fax: 702 873-3820
Web: www.swgas.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/05
Next EPS Date	03/13/2006

Price and Volume Information

Zacks Rank	3
Yesterday's Close	27.15
52 Week High	28.22
52 Week Low	23.70
Beta	0.26
20 Day Moving Average	108,780
Target Price Consensus	25.25



% Price Change

4 Week	0.82
12 Week	1.84
YTD	2.84

% Price Change Relative to S&P 500

4 Week	0.85
12 Week	-1.25
YTD	-0.24

Share Information

Shares Outstanding (millions)	39.12
Market Capitalization (millions)	1,062.22
Short Interest (shares)	1,325,304
Short Ratio	13.41
Last Split Date	N/A

Dividend Information

Dividend Yield	3.02%
Annual Dividend	$0.82
Payout Ratio	0.00
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	11/10/2005 / $0.20

EPS Information

Current Quarter EPS Consensus Estimate	1.02
Current Year EPS Consensus Estimate	1.35
Estimated Long-Term EPS Growth Rate	6.00

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.00
60 Days Ago	3.00

Next EPS Report Date	03/13/2006	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.25	vs. Previous Year	15.69%	vs. Previous Year	18.46%
Trailing 12 Months:	18.22	vs. Previous Quarter	-514.29%	vs. Previous Quarter:	-13.25%
PEG Ratio	2.38				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.39	12/31/05	-	12/31/05	-
Price/Cash Flow	4.83	09/30/05	7.31	09/30/05	1.87
Price / Sales	-	06/30/05	7.33	06/30/05	1.85
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	0.76	09/30/05	0.76	09/30/05	3.22
06/30/05	0.93	06/30/05	0.93	06/30/05	3.22
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	5.05	09/30/05	5.05	09/30/05	19.61
06/30/05	5.08	06/30/05	5.08	06/30/05	20.09
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	-	12/31/05	-	12/31/05	-
09/30/05	-	09/30/05	1.66	09/30/05	62.44
06/30/05	-	06/30/05	1.68	06/30/05	62.76

ZACKS PROFIT FROM THE PROS

Zacks.com Quotes and Research

WGL HLDGS INC WGL (NYSE)

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

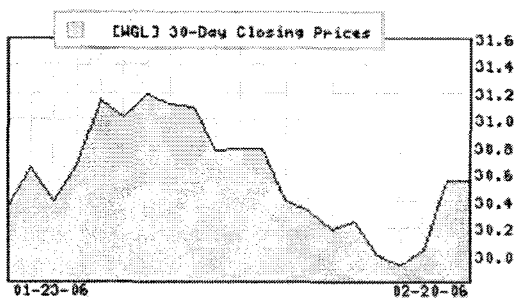
General Information

WGL HLDGS INC
101 Constitution Ave, N.W
Washington, DC 20080
Phone: 703 750-2000
Fax: -
Web: www.wglholdings.com
Email: apennix@washgas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities
Fiscal Year End	September
Last Reported Quarter	12/31/05
Next EPS Date	04/26/2006

Price and Volume Information

Zacks Rank	3
Yesterday's Close	30.55
52 Week High	34.52
52 Week Low	29.67
Beta	0.22
20 Day Moving Average	258,095
Target Price Consensus	30



% Price Change

4 Week	0.00
12 Week	1.36
YTD	1.63

% Price Change Relative to S&P 500

4 Week	0.03
12 Week	-1.71
YTD	-1.05

Share Information

Shares Outstanding (millions)	48.75
Market Capitalization (millions)	1,489.43
Short Interest (shares)	3,489,949
Short Ratio	16.47
Last Split Date	05/02/1995

Dividend Information

Dividend Yield	4.35%
Annual Dividend	$1.33
Payout Ratio	0.66
Change in Payout Ratio	-0.14
Last Dividend Payout / Amount	01/06/2006 / $0.33

EPS Information

Current Quarter EPS Consensus Estimate	1.22
Current Year EPS Consensus Estimate	1.83

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.00

Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	3.00
Next EPS Report Date	04/26/2006	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.38	vs. Previous Year	3.41%	vs. Previous Year	197.74%
Trailing 12 Months:	15.12	vs. Previous Quarter	464.00%	vs. Previous Quarter:	124.40%
PEG Ratio	4.10				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.66	12/31/05	10.73	12/31/05	3.58
Price/Cash Flow	7.74	09/30/05	10.71	09/30/05	3.69
Price / Sales	1.17	06/30/05	10.37	06/30/05	3.56
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/05	0.97	12/31/05	0.66	12/31/05	7.74
09/30/05	1.08	09/30/05	0.42	09/30/05	10.23
06/30/05	1.12	06/30/05	0.78	06/30/05	9.67
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/05	11.03	12/31/05	11.03	12/31/05	18.91
09/30/05	7.61	09/30/05	7.61	09/30/05	18.36
06/30/05	16.75	06/30/05	16.75	06/30/05	18.94
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/05	5.20	12/31/05	0.61	12/31/05	37.10
09/30/05	5.00	09/30/05	0.65	09/30/05	38.78
06/30/05	7.98	06/30/05	0.57	06/30/05	35.52

ATTACHMENT E

Infrastructure costs in the Water Utility Industry will continue to rise over the long term. Larger companies will acquire smaller ones in an effort to achieve economies of scale.

Foreign companies had been buying a number of U.S. water utilities, but that trend appears to be waning.

Water utility stocks are ranked to underperform the market over the coming 12 months; however, conservative investors can find attractive risk-adjusted choices here.

The Need For Consolidation

Long-term trends in the Water Utility Industry indicate that infrastructure costs will steadily rise. Many of the facilities and pipes that now purify and transport drinking water were built about 100 years ago. Ongoing upgrading and replacement are necessary for these old systems to remain in compliance with rules laid out by the Environmental Protection Agency (EPA). The cost of fixing and upgrading these systems is significantly higher than in the past (even adjusting for inflation) because more-expensive materials need to be used for modern construction. Moreover, transportation costs are much higher and should continue to rise, as nearby sources of water are depleted and farther-away bodies of water must be used. Water is quite difficult and expensive to move because it is heavy and cannot be compressed. Also adding to industry costs is the ongoing issuance of guidelines from the EPA that typically require water utilities to comply with more-stringent water-purity standards. Industry sources estimate that about $140 billion will be needed over the next 20 years to fund necessary water-system infrastructure improvements.

Small and mid-sized water companies usually welcome large-scale suitors. Smaller utilities generally lack the funds needed for long-term structural improvements, and might risk being out of compliance with local and federal laws at some point down the road. In an effort to prevent this unpleasant scenario from happening, many of these smaller companies welcome larger utilities that have the capital resources to remain in compliance with the law. The larger company gains greater geographic diversity from its acquisitions, which helps lessen its susceptibility to weather fluctuations that might cause volatility in earnings. Acquirers also benefit from economies of scale in which costs are generally reduced. Too, the regulatory-intensive nature of the Water Utility Industry means that some specific local governments might be more uncooperative with the utilities than other comparable local officials. A larger territory lessens the impact of a particularly onerous regulatory atmosphere.

INDUSTRY TIMELINESS: 81 (of 92)

Acquisition Update

Foreign companies have purchased a large number of domestic water utilities over the past year. These global water companies are attracted to this country's relatively safe political climate and its trend towards the privatization of municipal water and wastewater systems. Currently, there is concern among investors that the large premiums paid for U.S. takeover targets, which approached three times book value, will become more infrequent. British utilities are having regulatory difficulties at home that stand to weaken their designs on the U.S. market. Consequently, there appear to be fewer bidders in the market.

SDWA Regulations

The Safe Drinking Water Act (SDWA) of 1974 (amended in 1996) authorized the EPA to work with state and local governments to test for five potential impurities in drinking water every five years. The EPA mandates what levels of a certain contaminant is acceptable per a specified amount of water. Water utilities typically spend about 15% to 50% of their annual capital outlays in efforts to comply with SDWA guidelines. These companies must also stay in compliance with the Clean Water Act, and numerous state and local laws. At present, the EPA is considering lowering the allowable level of arsenic in drinking water from 50 parts per billion (ppb) to 5 ppb. This measure would be controversial because it would be lower than the standard of the World Health Organization (10 ppb) and would potentially cost domestic water companies billions of dollars.

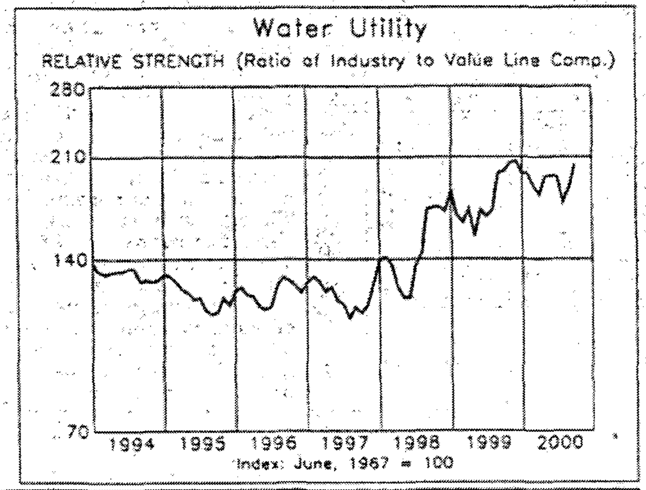
Investment Advice

Most of the water utility stocks that are covered in this review are not timely for the coming six to 12 months. Nonetheless, favorable Safety ranks among the group make some of these issues appealing for risk-averse investors seeking decent dividend yields.

Joseph Espaillat

Composite Statistics: Water Utility Industry

1996	1997	1998	1999	2000	2001		03-05
1793.3	1924.7	1994.2	2422.6	2550	2750	Revenues ($mill)	3500
214.4	2.9.2	265.6	295.3	315	335	Net Profit ($mill)	415
39.2%	37.3%	37.0%	38.2%	39.0%	39.0%	Income Tax Rate	39.0%
7.0%	6.3%	7.5%	8.7%	6.0%	6.0%	AFUDC % to Net Profit	6.0%
55.7%	56.5%	56.9%	55.9%	53.0%	52.0%	Long-Term Debt Ratio	50.0%
40.0%	39.6%	39.7%	42.0%	45.0%	46.0%	Common Equity Ratio	48.0%
5271.8	5703.3	6188.6	7223.7	7300	7900	Total Capital ($mill)	9300
6377.2	6785.5	7361.9	8961.3	8700	9300	Net Plant ($mill)	9700
6.0%	6.2%	6.2%	6.0%	6.5%	7.0%	Return on Total Cap'l	7.5%
9.2%	9.7%	10.0%	9.3%	10.5%	10.5%	Return on Shr. Equity	11.5%
9.7%	10.2%	10.4%	9.5%	11.0%	11.0%	Return on Com Equity	12.0%
3.3%	3.6%	3.9%	3.2%	3.5%	3.5%	Retained to Com Eq	4.5%
68%	66%	64%	67%	70%	70%	All Div'ds to Net Prof	80%
14.5	15.8	18.3	20.2	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	13.0
.91	.91	.95	1.15			Relative P/E Ratio	.85
4.6%	4.1%	3.4%	3.3%			Avg Ann'l Div'd Yield	5.0%



The events of September 11th have altered many priorities in the Water Utility Industry.

Long-term trends in the industry indicate that the cost of maintaining and upgrading water/wastewater systems will rise. The industry is consolidating, with larger companies acquiring smaller operators to achieve economies of scale.

Water Utility stocks are ranked to underperform the year-ahead market, though some of these issues offer conservative investors appealing risk-adjusted, total-return potential.

Security Issues

In response to the events of September 11th, the need to secure water systems against terrorism has become a top priority for regulators and water utilities alike, pushing many other legislative issues to the side. The FBI has stated that water companies should be on alert for potential threats in the months ahead. Many water companies are already heeding this warning, and incurring additional costs in the process that may limit near-term bottom-line growth. Also, the industry and regulators are working together to provide approximately $5 billion in federal funds for immediate infrastructure improvements as part of the pending economic stimulus legislation.

Industry Consolidation

Infrastructure costs in the Water Utility Industry will likely rise dramatically over the next 20 years. These companies have to maintain and upgrade their systems continually in order to remain in compliance with increasingly stringent rules issued by the Environmental Protection Agency (EPA) and local regulators. Many of the facilities and pipes that now treat and transport drinking water were built about a century ago. The costs of replacing those systems are significantly higher these days, even adjusting for inflation. Adding to the cost is the fact that nearby bodies of water tend to get depleted and expensive to use, so more-distant sources of water must be brought in to keep up with increasing demand for purified water. Water is difficult and costly to transport, since it is heavy and incompressible. All in all, industry sources estimate that over $140 billion will be needed to upgrade the nation's water-distribution system over the next 20 years.

The costs of staying in compliance with drinking water laws are especially onerous for smaller regional operators, since they have a limited base of customers over which to spread these costs. Small and mid-sized utilities generally welcome takeover offers from larger acquirers because of their superior capital resources. The acquiring utility attempts to achieve economies of scale through the transactions. Also, it gains greater geographic diversity, and that can reduce its susceptibility to unfavorable weather patterns and potentially burdensome local regulators.

INDUSTRY TIMELINESS: 85 (of 97)

Large-scale foreign acquirers have been very interested in purchasing domestic water utilities over the past few years, and the latest evidence is the generous takeover offer RWE AG made for *American Water Works*, the nation's largest public water company. RWE, a Germany-based firm, stands to gain cost synergies in the deal, along with geographic diversity in a politically stable country. Foreign utilities have been fascinated with the risk-adjusted earnings potential of U.S. water companies, and they are likely to continuing their buying spree over the next few years. As such, the number of investor-owned water providers with large territories is steadily dwindling. This development gives additional hope to those U.S. water utilities and investors looking for substantial buyout offers.

SDWA Regulations

The Safe Drinking Water Act (SDWA) of 1974 (amended in 1996) authorizes the EPA to work with state and local governments to test for five potential impurities in drinking water every five years. The EPA mandates what levels of a certain contaminant is acceptable per a specified amount of water. Water utilities usually spend a significant portion of their annual capital budgets on efforts to stay in compliance with SDWA guidelines. These companies must also comply with the Clean Water Act, and numerous state and local laws.

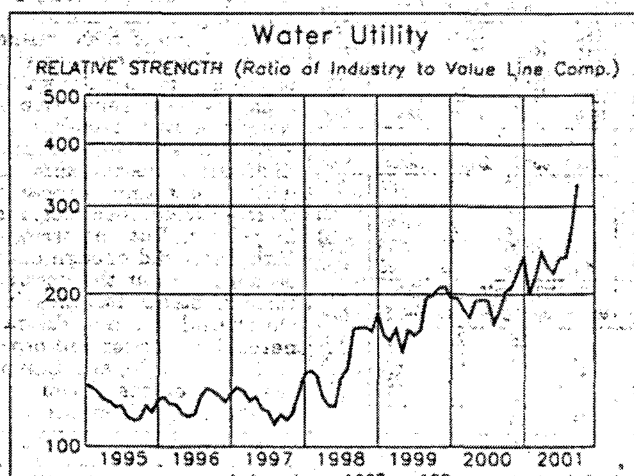
Investment Advice

The Water Utility stocks in this review are not timely for investment over the next six to 12 months. Nonetheless, a few of these issues possess favorable Safety ranks and solid dividend-growth prospects that may appeal to conservative investors.

Joseph Espaillat

Composite Statistics: Water Utility Industry

1997	1998	1999	2000	2001	2002		04-06
1439.5	1503.1	1898.0	2054.9	**2210**	**2315**	Revenues ($mill)	**2895**
183.2	192.9	232.8	254.2	**270**	**295**	Net Profit ($mill)	**410**
38.4%	39.1%	39.7%	40.1%	**40.0%**	**40.0%**	Income Tax Rate	**40.0%**
6.4%	7.9%	9.5%	5.5%	**6.5%**	**6.5%**	AFUDC % to Net Profit	**7.5%**
57.3%	58.0%	56.2%	54.9%	**54.5%**	**54.0%**	Long-Term Debt Ratio	**53.0%**
40.0%	39.7%	41.9%	44.0%	**44.5%**	**45.0%**	Common Equity Ratio	**46.0%**
4113.2	4524.6	5566.3	5654.6	**6055**	**6335**	Total Capital ($mill)	**7495**
5089.2	5544.7	7039.7	7545.4	**7975**	**8425**	Net Plant ($mill)	**9935**
6.5%	6.3%	6.2%	6.6%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
10.4%	10.2%	9.8%	9.8%	**10.5%**	**11.0%**	Return on Shr. Equity	**11.5%**
10.9%	10.5%	9.8%	9.9%	**10.5%**	**11.0%**	Return on Com Equity	**11.5%**
4.7%	4.4%	4.1%	4.0%	**4.5%**	**4.5%**	Retained to Com Eq	**5.0%**
57%	59%	59%	61%	**60%**	**59%**	All Div'ds to Net Prof	**52%**
15.2	19.4	19.2	16.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.5**
.88	1.01	1.09	1.06			Relative P/E Ratio	**.90**
3.7%	3.0%	3.0%	3.7%			Avg Ann'l Div'd Yield	**3.0%**



Infrastructure costs in the Water Utility Industry will rise considerably over the coming 20 years. Consequently, larger companies are buying smaller ones in an attempt to achieve economies of scale.

Water utility stocks are ranked to perform in the middle of the pack over the coming 12 months. Nonetheless, conservative investors can find above-average Safety ranks and attractive dividends in the group.

INDUSTRY TIMELINESS: 54 (of 98)

Industry Consolidation

Infrastructure costs in the water utility industry will likely soar over the next two decades. These companies must constantly repair and upgrade their existing water/wastewater systems in order to comply with increasingly strict rules issued by the Environmental Protection Agency (EPA) and local regulators. Many of the facilities and pipes that transport water were constructed over 100 years ago. The costs of replacing these systems is considerably higher now than it was in the past, even adjusting for inflation. Too, the ongoing depletion of nearby sources of water forces many water utilities to obtain water from more-distant, more-expensive sources. Water is difficult and costly to transport because it is heavy and incompressible. Nonetheless, utilities must continue to keep pace with rising demand for drinking water from growing residential and industrial customers. Recent estimates are that it will cost hundreds of billions of dollars to replace and upgrade failing water infrastructures over the next 20 years. This amounts to more than the entire current assets of the water industry in America. Much of these costs will likely be financed by federal spending and higher water rates. Nevertheless, water utilities are going to have to ante up much higher capital investments over the coming years.

The costs of staying in compliance with drinking water laws are especially onerous for smaller regional companies because they have fewer customers over which to spread their costs. Small and mid-sized water utilities tend to welcome takeover offers from larger, better-capitalized companies so that they can utilize the bigger firm's superior resources. For instance, the EPA's new rules on the allowable levels of arsenic in drinking water (10 parts per billion by January, 2006) is compelling some smaller utilities to merge with larger ones in an effort to remain in compliance with the new standards. By purchasing these smaller entities, large utilities seek to achieve economies of scale. Also, a bigger company gains greater geographic diversity that can reduce its susceptibility to unfavorable weather patterns and potentially burdensome local regulators. For example, the regulatory climate in California has been extra costly for utilities in the past couple of years, so companies, such as *California Water*, have been actively looking for acquisition targets outside of the state. On a positive note, the passage of a new law in California will allow water utilities to charge higher rates to customers (subject to refund) if regulators do not render decisions on rate cases within established processing periods. This ought to improve revenues for three out of four companies in this review.

Recent Challenges

The events of September 11, 2001 have introduced a whole new set of challenges for the industry. Companies have been spending a lot of time, energy, and money on making sure that their water systems are reasonably secure from potential terrorist attacks. Utilities have turned to local and federal regulators for reimbursement and additional funding, but the amount and timing of future funds is uncertain. Also, insurance costs have soared in the past year, as insurers are now more reluctant to cover companies, like water utilities, that can potentially have catastrophic losses.

SDWA Regulations

The Safe Drinking Water Act (SDWA) of 1974 (amended in 1996) authorizes the EPA to work with state and local governments to test for potential impurities in drinking water. The EPA mandates what particular level of a certain contaminant is acceptable per a specified amount of water. Water utilities routinely spend large portions of their annual capital expenditures on efforts to remain in compliance with SDWA guidelines. These companies must also comply with the 1972 Clean Water Act, and numerous other state and local laws, another costly endeavor.

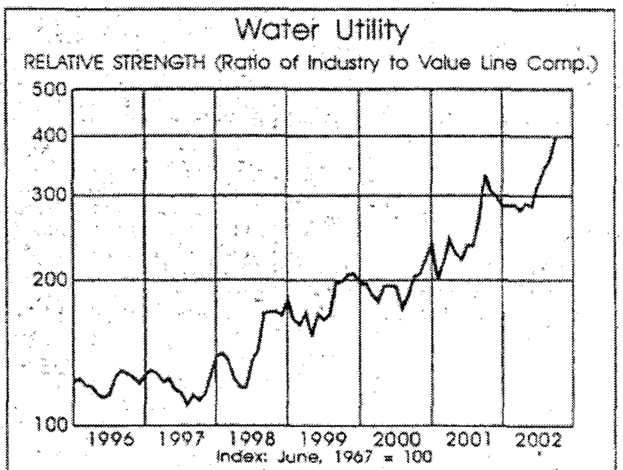
Decent Grounds For Conservative Investors

The water-utility stocks in this review are unlikely to outperform the year-ahead market. Nonetheless, they offer above-average Safety ranks, attractive dividend yields, and decent risk-adjusted total-return potential.

Joseph Espaillat

Composite Statistics: Water Utility Industry

1998	1999	2000	2001	2002	2003		05-07
1503.1	1898.0	2054.9	2190.5	**2495**	**2710**	Revenues ($mill)	**3360**
192.9	232.3	249.7	261.8	**275**	**315**	Net Profit ($mill)	**465**
39.1%	39.7%	40.1%	39.5%	**41.5%**	**40.0%**	Income Tax Rate	**40.0%**
7.9%	9.6%	5.5%	3.4%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
58.0%	56.2%	54.9%	56.7%	**57.0%**	**56.0%**	Long-Term Debt Ratio	**52.5%**
39.6%	41.9%	44.0%	42.4%	**42.0%**	**43.0%**	Common Equity Ratio	**47.0%**
4524.5	5566.3	5854.6	6198.1	**7005**	**7085**	Total Capital ($mill)	**8750**
5544.7	7039.7	7545.4	7991.2	**9210**	**9940**	Net Plant ($mill)	**12085**
6.3%	6.2%	6.6%	6.3%	**6.0%**	**8.5%**	Return on Total Cap'l	**7.0%**
10.2%	9.6%	9.8%	9.8%	**10.0%**	**10.5%**	Return on Shr. Equity	**11.5%**
10.5%	9.6%	9.9%	9.9%	**10.0%**	**10.5%**	Return on Com Equity	**11.5%**
4.4%	4.1%	4.0%	3.9%	**3.0%**	**4.5%**	Retained to Com Eq	**6.0%**
59%	59%	60%	61%	**61%**	**58%**	All Div'ds to Net Prof	**47%**
19.4	19.2	16.3	20.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.5**
1.01	1.09	1.06	1.07			Relative P/E Ratio	**.90**
3.0%	3.0%	3.7%	2.9%			Avg Ann'l Div'd Yield	**3.0%**



The Water Utility Industry's consolidation continues to gain momentum, as industry leaders look for opportunities to buy out smaller companies that are struggling to keep up with escalating infrastructure costs and heightened regulatory requirements.

Water Utility stocks are unlikely to outperform the broad market for the year ahead. With that said, however, some of these issues offer conservative investors attractive risk-adjusted, total-return potential.

Government Regulations

In order to keep water supplies safe, national purification standards have been established that the water industry is required to meet. Amended in 1996, the Safe Drinking Water Act (SDWA) of 1974 authorizes the Environmental Protection Agency (EPA) to work with state and local governments to periodically test for impurities in drinking water and regulate the levels of contaminants that are acceptable per a specified amount of water. These standards take into account the health effects of chemicals, measurement capabilities, and technical feasibility. One of the most significant contaminants that the industry screens for is arsenic, a naturally occurring substance. However, the EPA is in the process of lowering the tolerated amount of arsenic to 10 parts per billion from 20 parts currently. The change is expected to be in effect by January, 2006. Large chunks of water utilities' annual capital budgets are already spent on infrastructure maintenance and improvements in order to stay in compliance with the SDWA, the Clean Water Act, and numerous state and local laws. This percentage is likely to climb even higher, as fears of terrorism have prompted officials to further tighten regulation requirements.

Rising Infrastructure Costs

Along with the necessity to remain in compliance with increasingly strict water purity standards, water companies are also being pressured to continually upgrade aging facilities. Many of the water/wastewater systems that are presently in use were built over 100 years ago and are growing outdated. The costs associated with replacing these systems are dramatically higher now than when they initially were put in place. The EPA and other industry sources indicate that hundreds of billions of dollars over the next 20 years will be needed to repair the nation's entire water system. The Water Infrastructure Network believes that there will be a $12 billion annual shortfall for wastewater infrastructure over that period, and long-term help from the federal government is needed to solve the problem. Water companies will most likely foot the majority of the bill, though, as budget deficits at state and local levels will limit funds dedicated to the industry.

INDUSTRY TIMELINESS: 97 (of 98)

Industry Consolidation

With the costs of meeting safe drinking water guidelines on the rise, many smaller companies lack the funds to commit to long-term structural improvements. As such, these smaller water companies have been increasingly willing to accept takeover offers from larger suitors with significantly greater capital resources. The larger utilities benefit from economies of scale, which enables them to reduce overhead. In addition, the acquisitions usually enhance geographic diversity, reducing a company's vulnerability to weather fluctuations. Then, too, a multistate territory helps to alleviate a company's exposure to especially onerous regulatory atmospheres. Large foreign utilities have been particularly active in recent years, swallowing up domestic water companies in an effort to gain exposure to the United States' steady population growth.

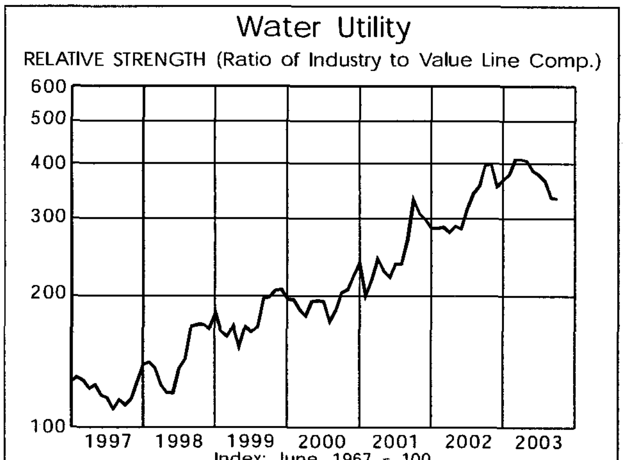
Investment Advice

None of the stocks under review are timely at this juncture, as poor weather conditions have resulted in inconsistent earnings patterns. Although *Philadelphia Suburban, California Water Services Group, and American States Water* all have below-average total-return potential out to 2006-2008, income-oriented investors might may find one of these stocks attractive, given their favorable risk profile. Income-bearing stocks have gained some additional popularity of late, because of the recent federal tax bill that reduced the top rate investors pay on dividend income to 15%. As usual, though, we recommend that potential investors careful review individual reports before making any new commitments.

Andre J. Costanza

Composite Statistics: Water Utility Industry

1999	2000	2001	2002	2003	2004		06-08
637.2	704.3	751.8	794.4	***845***	***950***	Revenues ($mill)	***1185***
72.4	90.9	95.4	106.6	***105***	***130***	Net Profit ($mill)	***190***
40.0%	41.2%	40.2%	38.8%	***39.0%***	***39.5%***	Income Tax Rate	***40.0%***
--	--	--	--	***Nil***	***.5%***	AFUDC % to Net Profit	***.5%***
51.1%	50.3%	52.4%	53.9%	***53.0%***	***51.5%***	Long-Term Debt Ratio	***51.0%***
48.3%	49.3%	47.2%	45.9%	***46.5%***	***48.5%***	Common Equity Ratio	***49.0%***
1444.7	1661.0	1840.7	1973.6	***2250***	***2425***	Total Capital ($mill)	***3050***
2100.3	2342.5	2532.3	2751.1	***3025***	***3225***	Net Plant ($mill)	***3950***
7.4%	7.0%	6.8%	7.0%	***6.5%***	***7.0%***	Return on Total Cap'l	***7.5%***
11.5%	10.7%	10.6%	11.2%	***10.0%***	***10.5%***	Return on Shr. Equity	***12.0%***
11.5%	10.8%	10.7%	11.2%	***10.0%***	***11.0%***	Return on Com Equity	***12.0%***
3.8%	3.6%	3.3%	3.9%	***3.0%***	***4.0%***	Retained to Com Eq	***5.5%***
68%	67%	69%	66%	***75%***	***65%***	All Div'ds to Net Prof	***54%***
19.5	18.6	22.6	21.5	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***13.5***
1.11	1.21	1.16	1.17			Relative P/E Ratio	***.90***
3.5%	3.6%	3.1%	3.1%			Avg Ann'l Div'd Yield	***3.0%***



INDUSTRY TIMELINESS: 94 (of 98)

The Water Utility industry continues to rank near the bottom of the *Value Line* investment universe. Infrastructure costs will limit earnings for at least the near future, as the high expenses associated with maintaining and improving the country's water-distribution systems continue to rise.

However, it appears that relief is on the way for some companies. Favorable regulatory rate case rulings have been handed down across the country and look as though they might become the norm.

Meanwhile, consolidation remains the name of the game. Although many of the industry's smaller players lack the capital requirements to meet growing government regulations, larger companies are using the consolidation as way to boost profitability via growing its customer base.

Infrastructure Costs

Infrastructure costs continue to climb higher as water utility companies, with little help from strapped government branches, are forced to deal with maintaining and upgrading existing facilities. Costs are becoming an even greater concern as time passes because a number of the functioning systems currently in place are over 100 years old and in need of significant repair. That said, we believe that it will take hundreds of billions of dollars to renovate existing pipelines over the next few decades. To make matters worse, the costs of staying in compliance with regulatory laws are growing even more difficult, due to fears of terrorist activities against the country's drinking supplies. Although the Safe Drinking Water Act (SDWA) of 1974 remains the authority for the safety and purity of drinking water, recent amendments are making compliance even more demanding. In 1996, an amendment authorized the Environmental Protection Agency (EPA) to step up local compliance levels. And, governing law-makers now insist that the EPA work with local and state governments to test for impurities in drinking water and to regulate the levels of contaminants that are acceptable.

A Buying Opportunity

The growing regulations and costs associated with staying in compliance with government standards related to the quality and purification of drinking water is forcing many of the smaller water companies to look to larger suitors. Bigger companies with the market scale to withstand the current onslaught of costs are clearly taking advantage of this situation. Indeed, these firms are growing their businesses at relatively low costs as well as diversifying their operations into less regulated and more-rapidly developing areas of the U.S. *Aqua America* is a perfect example, making nearly 20 acquisitions since the close of last year. *Aqua* recently purchased a number of Pennsylvania-based companies in order to help drive top-line growth. We anticipate that the current consolidation theme will persist, as we expect restructuring costs to continue to rise.

Regulatory Assistance

Although water utility company's have been forced to deal with lethargic case rulings in the past couple of years, some governing bodies are picking up the pace. In California, for example, the California Public Utilities Commission (CPUC) has handed down a number of favorable rate-relief rulings in recent months, and more are expected. With the California electric crisis seemingly in the rearview mirror, the current administration seems intent on delivering more timely assessments. *American States Water Company* and *California Water Service Group* have both seen profits benefit from recent case rulings over the past quarter.

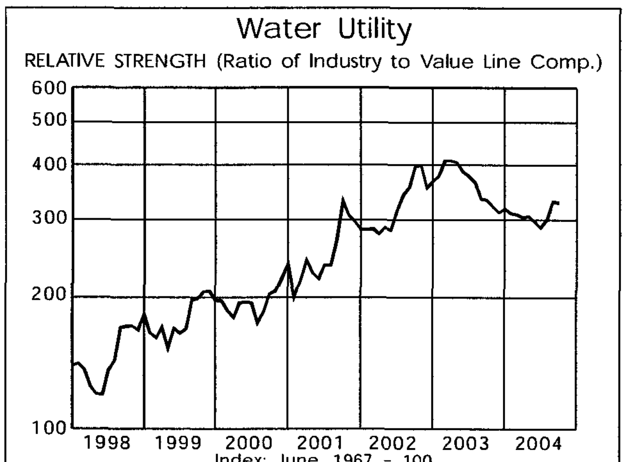
Investment Advice

Most investors will want to take a pass on the stocks covered in the next few pages, as they offer uninspiring returns out to decade's end. In addition, not one of the stocks in this edition is ranked to outperform the market in the next six to 12 months. Nonetheless, income-oriented investors may like the industry's solid dividend yields. *California Water* may have some added appeal for the risk-averse, given its above average Safety rank. Still, we advise that potential investors carefully review the individual reports in the ensuing pages before making a commitment to any of the stocks mentioned above.

Andre J. Costanza

Composite Statistics: Water Utility Industry

2000	2001	2002	2003	2004	2005		07-09
704.3	751.8	794.4	857.0	**990**	**1075**	Revenues ($mill)	**1345**
90.9	95.4	106.6	98.6	**130**	**150**	Net Profit ($mill)	**205**
41.2%	40.2%	38.8%	40.0%	**40.0%**	**40.0%**	Income Tax Rate	**40.0%**
-	--	--	--	**Nil**	**Nil**	AFUDC % to Net Profit	**Nil**
50.3%	52.4%	53.9%	51.2%	**51.0%**	**51.0%**	Long-Term Debt Ratio	**50.0%**
49.3%	47.2%	45.9%	48.6%	**49.0%**	**49.0%**	Common Equity Ratio	**50.0%**
1661.0	1840.7	1973.6	2296.4	**2615**	**2870**	Total Capital ($mill)	**3550**
2342.5	2532.2	2751.1	3186.1	**3400**	**3605**	Net Plant ($mill)	**4150**
7.0%	6.8%	7.0%	5.9%	**6.5%**	**7.0%**	Return on Total Cap'l	**7.0%**
10.7%	10.6%	11.2%	8.8%	**9.5%**	**9.5%**	Return on Shr. Equity	**10.0%**
10.8%	10.7%	11.2%	8.8%	**9.5%**	**9.5%**	Return on Com Equity	**10.0%**
3.6%	3.3%	3.8%	2.5%	**3.5%**	**4.0%**	Retained to Com Eq	**4.5%**
67%	69%	66%	72%	**62%**	**58%**	All Div'ds to Net Prof	**52%**
18.6	22.6	21.5	26.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**18.0**
1.21	1.16	1.17	1.49			Relative P/E Ratio	**1.20**
3.6%	3.1%	3.1%	2.8%			Avg Ann'l Div'd Yield	**3.5%**



INDUSTRY TIMELINESS: 93 (of 98)

After showing some brief signs of a turnaround last year, the Water Utility Industry appears to have reverted back to its old ways. Feeling the effects of uncooperating weather conditions and high infrastructure costs, the stocks in this industry have had trouble meeting earnings expectations and, as a result, have sorely underperformed the broader market in recent months. In fact, none of the water utility stocks that are covered in the next few pages are ranked better than 3 (Average) for Timeliness, based on our momentum based ranking system. As a whole, the industry ranks near the bottom of the Value Line investment universe.

And the future does not look much brighter. Although a more favorable regulatory landscape and normalized weather conditions ought to provide a better landscape, we are concerned that rapidly growing infrastructure costs will continue to undermine this group's earnings out to late decade.

Easing Tensions

Although designed to keep a balance of power between consumers and providers, regulatory authorities, have long been a thorn in the side of water utility companies. Rate relief case decisions had often been unfavorable and untimely, with some rulings being pushed off for as long as two years. But, it finally looks as though things are taking a turn for the better, especially in the state of California. The California Public Utilities Commission (CPUC), which is responsible for ruling on general rate case requests in the Golden State, has been handing down more-favorable and timely decisions in recent months, thanks, in part, to the efforts of Governor Schwarzenegger. He has replaced members thought to be antagonists of rate relief with more-business-friendly members, and additional moves may be in the works. The recent changes makes for a favorable backdrop for water utility companies operating in California, such as *American States Water Co.* and *California Water Service Group.*

Costs

But, while regulators are easing their stance on rate case decisions, this does not look to be the case for infrastructure demands. Many of the current infrastructures are upwards of 100 years old and are in severe need of maintenance and, in some cases, massive renovations and rebuilding. And, given the geopolitical volatility worldwide and the heightened threat of bioterrorism on U.S. water pipelines and reservoirs, these costs are likely to continue to only rise, as companies strive to comply with EPA water purification standards. Infrastructure repair costs are expected to climb in the hundreds of millions of dollars over the next two decades, putting many smaller water companies at a distinct disadvantage. With a dearth of resources to fund these improvements, many such companies are being forced to sell. But, given the current landscape, larger companies with the flexibility and capital to deal with the higher costs are utilizing the weakness to add additional legs of growth to their businesses. *Aqua America*, the largest water utility in our survey, for example, has made more than 90 acquisitions in the past five years, doubling its revenue base during that time. The company does not seem to be slowing its aggressive spending ways and has the highest return on equity of any of the stocks that we cover here.

Investment Advice

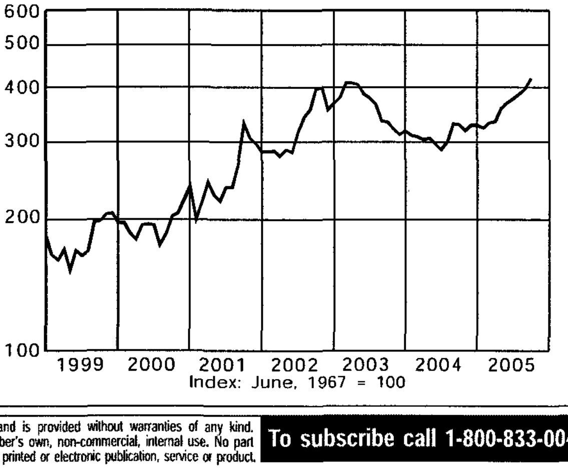
Most investors will probably want to take a pass on the stocks in this industry. Typically market laggards, not one of the issues covered in the next few pages stands out for near-term or long-term capital gains potential. The limited financial resources of most of these companies, along with the capital-intensive nature of the industry, will probably limit any substantial growth out to late decade.

Those seeking to add an income component to their portfolio may find an attractive option here, though. Each of the stocks in this industry carries an above-average dividend yield, with *American States Water* and *California Water* offering the highest percentages. *California Water* offers some additional appeal, as it has a 2 (Above Average) Safety rank. As is always the case, we recommend that all potential investors take a more in depth look at the individual reports on the following pages before considering making any future financial commitments.

Andre J. Costanza

Composite Statistics: Water Utility Industry

2001	2002	2003	2004	2005	2006		08-10
751.8	794.4	857.0	985.6	**1250**	**1350**	Revenues ($mill)	**1725**
95.4	106.6	98.6	122.4	**155**	**170**	Net Profit ($mill)	**235**
40.2%	38.8%	40.0%	39.4%	**39.5%**	**39.5%**	Income Tax Rate	**39.5%**
--	--	--	--	**Nil**	**Nil**	AFUDC % to Net Profit	**Nil**
52.4%	53.9%	51.2%	50.0%	**52.0%**	**51.0%**	Long-Term Debt Ratio	**48.0%**
47.2%	45.9%	48.6%	50.0%	**48.0%**	**49.0%**	Common Equity Ratio	**52.0%**
1840.7	1973.6	2296.4	2543.6	**3000**	**3400**	Total Capital ($mill)	**4100**
2532.2	2751.1	3186.1	3532.5	**4050**	**4250**	Net Plant ($mill)	**5000**
6.8%	7.0%	5.9%	6.7%	**7.0%**	**7.5%**	Return on Total Cap'l	**7.0%**
10.6%	11.2%	8.8%	10.7%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.5%**
10.7%	11.2%	8.8%	10.7%	**11.0%**	**11.0%**	Return on Com Equity	**11.5%**
3.3%	3.8%	2.5%	4.6%	**5.0%**	**5.0%**	Retained to Com Eq	**3.0%**
69%	66%	72%	57%	**60%**	**55%**	All Div'ds to Net Prof	**45%**
22.6	21.5	26.0	25.5	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	**18.0**
1.16	1.17	1.48	1.36			Relative P/E Ratio	**1.20**
3.1%	3.1%	2.8%	2.2%			Avg Ann'l Div'd Yield	**3.4%**



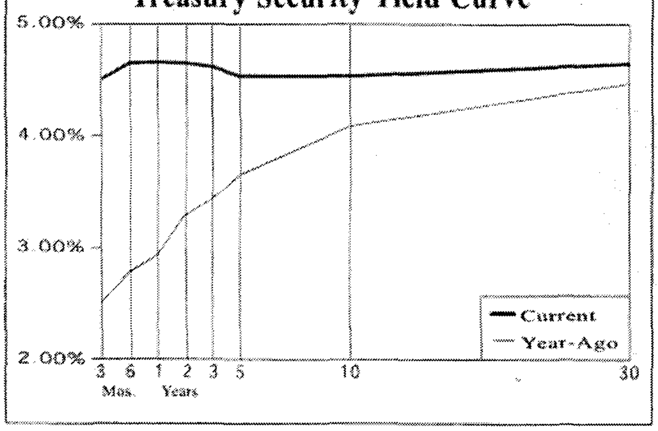
ATTACHMENT F

Selected Yields

TAXABLE

	Recent (2/09/06)	3 Months Ago (11/10/05)	Year Ago (2/10/05)
Market Rates			
Discount Rate	5.50	5.00	3.50
Federal Funds	4.50	4.00	2.50
Prime Rate	7.50	7.00	5.50
30-day CP (A1/P1)	4.50	4.01	2.51
3-month LIBOR	4.74	4.33	2.79
Bank CDs			
6-month	2.87	2.21	1.76
1-year	3.44	2.65	2.21
5-year	3.97	3.48	3.51
U.S. Treasury Securities			
3-month	4.51	3.96	2.51
6-month	4.65	4.29	2.78
1-year	4.66	4.37	2.93
5-year	4.54	4.48	3.66
10-year	4.54	4.55	4.09
10-year (inflation-protected)	2.04	2.06	1.52
30-year	4.65	4.74	4.47
30-year Zero	4.56	4.67	4.52

	Recent (2/09/06)	3 Months Ago (11/10/05)	Year Ago (2/10/05)
Mortgage-Backed Securities			
GNMA 6.5%	5.34	5.55	4.30
FHLMC 6.5% (Gold)	5.88	5.93	4.41
FNMA 6.5%	5.77	5.73	4.27
FNMA ARM	4.47	4.15	3.22
Corporate Bonds			
Financial (10-year) A	5.43	5.46	4.86
Industrial (25/30-year) A	5.71	5.65	5.21
Utility (25/30-year) A	5.69	5.64	5.10
Utility (25/30-year) Baa/BBB	6.05	6.08	5.57
Foreign Bonds (10-Year)			
Canada	4.21	4.16	4.16
Germany	3.48	3.52	3.45
Japan	1.57	1.58	1.41
United Kingdom	4.16	4.43	4.51
Preferred Stocks			
Utility A	7.03	7.17	6.80
Financial A	6.22	6.31	5.92
Financial Adjustable A	N/A	5.51	5.18



Treasury Security Yield Curve

TAX-EXEMPT

	Recent (2/09/06)	3 Months Ago (11/10/05)	Year Ago (2/10/05)
Bond Buyer Indexes			
20-Bond Index (GOs)	4.42	4.55	4.27
25-Bond Index (Revs)	5.14	5.22	4.79
General Obligation Bonds (GOs)			
1-year Aaa	3.25	3.05	2.21
1-year A	3.37	3.17	2.36
5-year Aaa	3.48	3.45	2.75
5-year A	3.76	3.73	3.02
10-year Aaa	3.84	3.94	3.36
10-year A	4.16	4.28	3.64
25/30-year Aaa	4.37	4.59	4.32
25/30-year A	4.64	4.85	4.54
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.37	4.70	4.35
Electric AA	4.47	4.74	4.37
Housing AA	4.64	4.78	4.55
Hospital AA	4.89	5.02	4.60
Toll Road Aaa	4.58	4.76	4.45

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/1/06	1/18/06	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1328	1210	118	1703	1804	1722
Borrowed Reserves	40	180	-140	134	246	198
Net Free/Borrowed Reserves	1288	1030	258	1568	1558	1524

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/30/06	1/23/06	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1408.3	1388.1	20.2	10.2%	7.1%	2.3%
M2 (M1+savings+small time deposits)	6740.0	6758.1	-18.1	6.4%	5.6%	4.4%
M3 (M2+large time deposits)	10271.5	10273.4	-1.8	8.8%	9.8%	7.8%